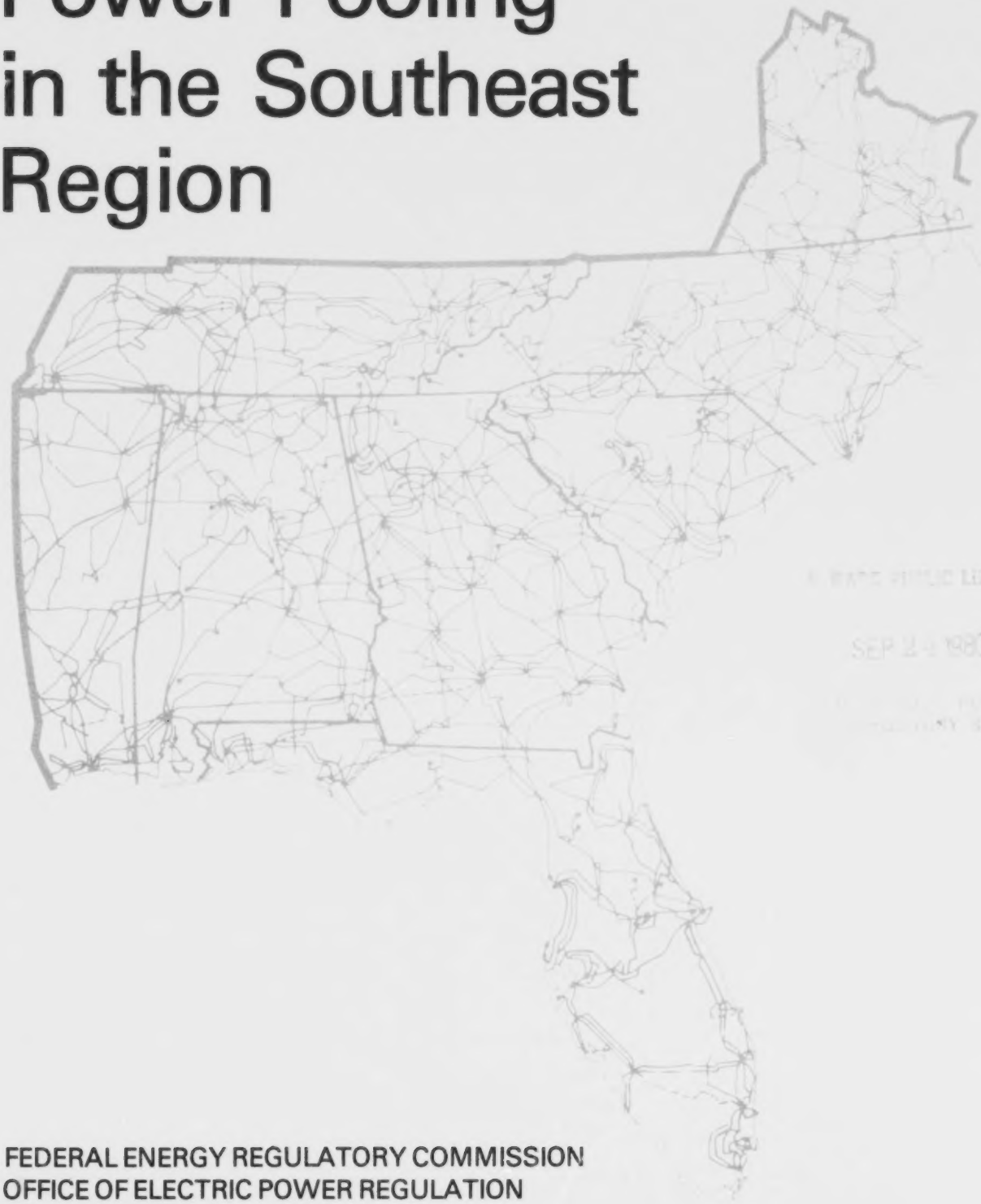
FERC-0051

Power Pooling in the Southeast Region



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Power Pooling in the Southeast Region

Prepared by the
Southeast Regional Task Force

Federal Energy Regulatory Commission
Office of Electric Power Regulation
Washington, DC 20426

August 1980

FOREWORD

This report is one of five regional reports prepared by task forces as part of the Federal Energy Regulatory Commission (FERC) power pooling study under the provisions of Section 205(b) of PL 95-617, the Public Utility Regulatory Policies Act of 1978 (PURPA). The Act directs the Commission to conduct a study of power pooling and report its findings to the President and Congress. The purpose of the study is to examine "the opportunities for (a) conservation of energy, (b) optimization in the efficiency of use of facilities and resources, and (c) increased reliability through power pooling arrangements."

The regional task forces were formed after consultations with industry and regulatory representatives. Although various industry and government organizations suggested candidates to serve on the task forces, the membership selection was made by the Commission. The task forces were not advisory and did not provide recommendations. Each member of the five regional task forces served primarily as an individual, contributing personal knowledge and interpretations, and provided information on industry activities and problems on the basis of this expertise. To some degree members reflected the views of their own industry segment, e.g., investor-owned utility, holding company, regulatory, municipal association, or government; but the proceedings stressed individual evaluations.

The regional reports reflect the work of the task forces in addressing the characteristics and problems of coordinated electric power operations in each region. The purpose of the task forces was to assist in developing a regional-specific factual understanding of the development, status, problems, plans, benefits, costs, industry and regulatory views, and other significant aspects and characteristics of power pooling in the region.

In addition to the regional task force reports, which are primarily descriptive, the Commission is providing for the President and Congress, in a separate report, its overall assessment of the status of power pooling and the prospects for increased application of power pooling in the United States by the electric utility industry. The Commission's assessment and report will be based to a large degree on the reports and proceedings of the task forces. In addition, it will also be based on Commission files, the results of staff analyses and evaluations of specific power pools, and the comments of interested persons in agencies such as reliability councils, industry trade associations, the National Association of Regulatory Commissioners, and the Department of Energy.

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NOTE: Although the individual members of the task force are in basic agreement with the contents of the report itself (Chapters 1 through 4), each does not necessarily agree with the comments or interpretations of events of a historical nature that are contained in the remaining portions of the report.

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EXECUTIVE SUMMARY

The electric utilities in the Southeast Region serve all of North Carolina, South Carolina, Georgia, Florida, Alabama, Tennessee, and parts of Virginia, West Virginia, Kentucky, and Mississippi. This area is coincident with the area included in the Southeastern Electric Reliability Council (SERC) and is shown in Figure 1. This region, perhaps better than any other, represents the pluralistic nature of the industry. It includes within its directly or indirectly interconnected entities a very large Federal system; a State system; a county system; many municipal systems, large to small; generation and transmission cooperatives; distribution cooperatives; a Federal marketing agency; and industries with generation, together with a very large investor-owned holding company and many investor-owned systems, most relatively large.

The beginnings of the industry in this region can be traced easily from the 1890's to street railway and street lighting entities, small municipal ice making plants, and various industries, notably the textile industry. Even though pooling and coordination agreements were being reached by the electric utilities prior to the mid-1930's, the economic, political, and social conditions of that period could be said to have established the pattern for the subsequent rapid growth in coordination, interconnection, and pooling activities. This period produced some intense utility rivalries and philosophical differences of an economic nature, traces of which remain today. Nevertheless, the mutual desire of all utilities to support the World War II production effort, much of which was concentrated in this region, served to reinforce the principle of mutually supporting operations. This cooperation continued into the postwar period which saw this region achieve rapid economic growth in all sectors, including the use of electrical energy.

During the 1930's and 1940's, the utilities of the region explored and used all conceivable avenues of coordination and pooling. The purchase, sale, and interchange of capacity and energy, including third party transactions, soon reached a high degree of utilization and sophistication. This coordination included such items as shared costs in extra-high voltage (EHV) transmission interconnections, and large generating units. It also included accepting the technical and administrative discipline necessary to participate in a large, mutually supporting operation involving system frequency and time control. This discipline was effected through the region's participation in the Interconnected Systems Group (ISG), an early pioneer in these areas and a predecessor of the North American Power Systems Interconnection Committee (NAPSIC). These early experiences so convinced the utilities of this region of the favorable economics of the pooling concept that generally, the concept has been advanced continuously. An economic measure of the progress and the degree of attainment is given in the following figures, which represent some of the utilities' estimates of their

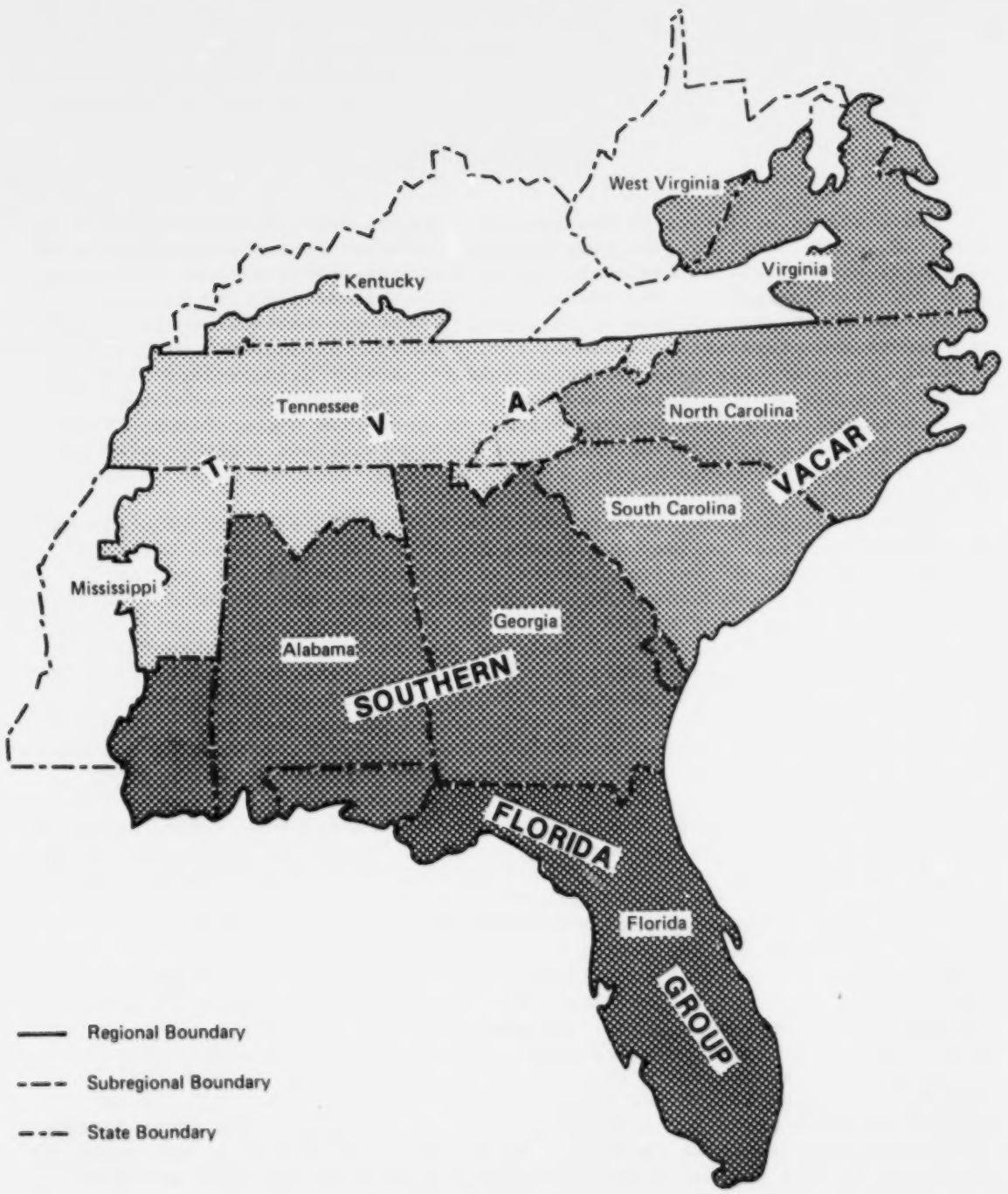

FIGURE 1--The Four Major Power Pooling Areas Within the Southeast Region

benefits received from the pooling concept for the year 1978, as contrasted with independent operations: Virginia-Carolinas Subregion (VACAR) estimates the value of interchange transactions to be $9.1 million; Southern Company estimates a total savings of $51.3 million from seasonal exchange of capacity, operating reserve coordination, emergency capacity and energy exchange, economic dispatch and peak-hour diversity; Florida Electric Power Coordinating Group (FCG) reports a saving of $16.5 million in economy energy exchanges due to the Energy Brokerage System; and TVA reports a savings of $29 million in fiscal year 1978 from certain types of energy interchange transactions.

Even with this background and experience, it is generally felt that the opportunities for increased pooling activities are either limited or constrained by numerious factors in today's environment. In some instances, where public and investor-owned utilities are involved, an impediment revolves around the economics and equity of financing methods between the two entities, and how such differences should be handled in rate structures. However, this issue appears to be moving toward workable solutions, as evidenced in Georgia. This feeling of limited opportunity is not restricted to cooperative efforts between investor-owned and public utilities but also appears to exist for some situations involving only private utilities, where relative size is a factor. Generally, the group felt that coordination efforts brought about by mutual desire to improve systems reliability automatically provide for increased pooling activities, as the need or benefit arose.

In considering the pooling issues and problems in the four general areas--technical, institutional, legal, and financial--two issues appeared to stand out to many of the task force members. The first issue is a matter of vulnerability of signators to an agreement to possible antitrust action under existing laws. Heretofore, the very nature of the industry, i.e., the regulated, legal, or natural monopoly character, has been accepted as being in the best interest of the consumer, and so has the development of agreements with other utilities. However, introduction of the antitrust issue into the sometimes adversary relationships between entities in this industry has severely dampened the enthusiasm for contractual pooling activities. The second issue is the changing operating conditions that the electric utility companies are experiencing because of the numerous Federal and State environmental regulations. These regulations, by prohibiting the use of certain fuels or limiting the location of electric production facilities, have increased costs of operation and created fuel shortages in parts of the Southeast Region. Therefore, the impact of these regulations in some instances has discouraged the electric utilities from entering into long-term contractual pooling arrangements.

Although legal issues such as environmental regulations and antitrust are of immediate concern to the industry, it may be that in the long run the technical, financial, and institutional issues and problems are the more formidable concerns. Given the valid national interest in conservation of energy, efficient use of facilities and resources, and increased reliability through electric power pooling arrangements, all potential concerns should be evaluated.

The Southeast Region is divided into four subregions: Southern, Tennessee Valley Authority (TVA), Virginia-Carolinas (VACAR), and Florida. All four are geographically large in area (Southern, TVA, and VACAR are each larger than the six New England states together, and Florida is nine-tenths as large). The loads in each area are sufficiently large to support state-of-the-art sized generating units and transmission lines. The first three subregions are heavy users of coal as a fuel; the Florida group presently relies heavily on oil. There are many subregion interties, but some interchange scenarios would require additional ties. The Southern and TVA Subregions are each controlled by one control center, utilizing economic-cost-of-delivered-power computers. VACAR has six control centers. Florida, which has thirteen control centers, utilizes a central coordinating group for disseminating information over communication networks to accomplish economic optimization of generation, and other pool operating functions.

Coordination and pooling is accomplished in various ways in the four subregions.

In the TVA Subregion, TVA plans and operates the entire bulk electric system. Although TVA is not made up of several companies, it can be considered a pool in that it is centrally dispatched and controlled from five dispatching areas, and interconnected at 30 points.

In the Southern Subregion, the subsidiaries of the Southern Company (a holding company) generate over 90 percent of the electrical energy. The four operating subsidiaries are physically interconnected at multiple points and operate as a single integrated electrical system.

The generation and system planning is performed by each operating company to meet its anticipated electrical load, but a total coordinated planning effort with the other operating companies results in a total system wide generation expansion plan to satisfy future needs. The operating companies are assisted with their system and generation planning by Southern Company Services Inc., a service company subsidiary. Other major organizations in the Southern Subregion represent an investor-owned utility, consumer-owned utilities, or public utilities. These organizations are Alabama Electric Cooperative, Inc., Municipal Electric Authority of Georgia, Savannah Electric and Power Company, Oglethorpe Power Corporation, Southeast Power Administration, and South Mississippi Electric Power Association. For the most part, the electric coordination agreements made between all the utility organizations in the Southern Subregion have been made between the subsidiaries of the holding company (Southern Company) and the individual consumer-owned and public utilities. The majority of these electrical coordination agreements have involved short- to medium-term contracts dealing with reserve support, emergency outages, wheeling arrangements, and interchanges. However, some generating plants and transmission facilities have recently been built by several of the utility organizations in the subregion as joint owners.

In the VACAR Subregion, the utilities that make up the VACAR group produce over 90 percent of the electrical energy. The companies' coordinating body, the VACAR executive committee, has established task forces for the operating and planning functions of the VACAR group.

This committee and the various task forces are made up of different members of each company. The task forces produce studies which are presented

to the group members and distributed to the individual companies whose planning departments use the information for generation and system planning. Through this arrangement the individual companies have developed and maintained workable agreements which permit the transfer of capacity and energy within the VACAR group under practically any operating condition.

In the Florida Subregion, the member systems of the Florida Electric Power Coordinating Group (FCG) produce nearly all of the electrical energy. The FCG has a Planning Committee responsible for conducting a program of studies and reporting its results to the FCG's members. The individual members then use this information in their own planning functions. The Operating Committee of the FCG forms the basis of a pool for all operating functions except central dispatch. This central dispatch function is approximated by a computerized energy broker system that coordinates the operations of its members. Through information provided hourly by each the 13 dispatch offices, energy buyers and sellers are matched to take advantage of the best combinations of operating decremental and incremental costs. This method has provided the FCG members with significant cost savings. A totally computerized central commitment and dispatch system is also under consideration.

In Florida, the rural electric cooperatives have formed the Seminole Electric Cooperative, Inc., which functions as a generation and transmission cooperative for its member systems. Seminole is a member of the FCG and participates actively on all committee levels. The municipals in Florida have recently formed the Florida Municipal Power Agency (FMPA) for the purpose of planning generation facilities, and financing and operating those facilities.

COORDINATION BETWEEN SUBREGIONS

The electric coordination planning between subregions is normally conducted by study groups made up of members of the utility organizations that produce the preponderance of the electric energy in each subregion. These studies are conducted on the macro level; that is, if a study identifies an area where the facilities to transfer power or energy between subregions might be inadequate in the future, the results of that study will be reported to the affected utilities. It is then the responsibility of the affected utilities to work out the solution to the problem. This same type of coordination exists between the Southeast Region's subregions and the regions outside the Southeast Region. The Southeastern Electric Reliability Council (SERC), made up of members of the utilities in the Southeast, has provided the guidelines and standards for bulk power systems' reliability, operations,and planning, and has assisted the utilities in making the subregional and regional coordination studies.

Diverse factors have resulted in the particular characteristics of the subregional coordinating bodies. In the TVA Subregion, the dominant factor was the formation of the TVA by Congress in 1933. In the Southern Subregion, the holding company group of utilities was formed in the 1920's based on the availability of fuel and water supplies to produce electric power, the location of major load centers, and various legislative and judicial

decisions. The coordinating organizations' characteristics in the Florida Subregion have been influenced by the peninsular feature of Florida, the population growth, the type and location of the electrical loads that have developed in the State, and recent legislative and regulatory actions from the State. In the VACAR Subregion, the characteristics of the coordinating body reflect such factors as the availability of fuel and water supplies, the location of load centers, and an unsatisfactory experience with a formal contractual power pool.

Although the task force considers a single control center for the entire Southeast Region not technically and economically desirable at this time, it is possible that Florida and VACAR will evolve into an operating mode where each has its own central control center that operates with the concept of delivering power at the most economic cost. Florida, with its FCG broker concept, could be said to be moving in that direction now. VACAR, with the unsuccessful CARVA history, can see little advantage in such a central control area at present, feeling equal benefits are obtainable under their present coordinating agreements.

Presently, a limited fuel-by-wire capability can use coal consumption elsewhere in the Southeast Region to displace Florida oil consumption. Increasing this capability would require the addition of expensive transmission lines. However, this is not the major concern in achieving such a coordination pattern. Assuming the matters of rates, tariffs and equitable cost allocations are solvable, the major concern is the timely availability of coal, particularly in the short term. The nature of the coal supply for electric utilities is affected by long-term contracts of ten years or more involving the logistics of transportation and mining; except in an emergency or under contract, it may not be prudent for a coal burning utility to deplete its own inventory or supply to displace another fuel in another area. Consequently, long-term fuel-by-wire arrangements would require separate long-term fuel contracts as well as committed generation and transmission facilities. Considering the procurement and construction time constraints, it may be more desirable, and in the best interest of area reliability, for the Florida utilities to continue to develop coal-fired generation within the peninsula in addition to depending on transmission from the north.

The task force members all felt that pooling in the Southeast Region had reached a high degree of use and sophistication to the benefit of all, but because of the several factors highlighted above, considered in detail in the body of the report, significant additional benefits in the next two decades would be realized at a lower rate than in the past.

CHAPTER 1
INTRODUCTION

This report describes the degree to which pooling coordination exists between utilities in the southeastern region of the United States, examines the potentials for further beneficial pooling coordination, and identifies impediments that could hinder realization of the potential benefits.

The Southeast Region covers an area coincident with that of the Southeastern Electric Reliability Council (SERC), including all or part of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia. The Council's subregions, Florida, Southern, Tennessee Valley Authority, and Virginia-Carolinas, correspond to the geographic pooling coordination areas and groupings of utilities in the Southeast Region (see Chapter 2).

DEFINITION OF POWER POOLING

The term "power pooling" does not have a precise and standardized definition because of the diverse nature of electric power systems, the increase in the number of types of interconnection agreements between electric utilities, and the different views of individuals regarding the definition of power pooling. Conceptually, the term has been used to imply the joint operation and planning of two or more utility systems as though they were a single system. In practice, this situation has never been totally achieved because of the separate legal and ownership responsibilities of the individual systems. Coordination, therefore, has ranged from informal planning coordination to formal contractual agreements with specific penalties for nonconformance. In the past, the Federal Energy Regulatory Commission (FERC) has tended to classify as "pools" only systems that have filed formal contractual agreements. However, the terms of contractual agreements vary widely and several groups call themselves pools although they do not have contractual agreements. Therefore, the study of power pooling is an examination of the whole spectrum of coordination arrangements, although the greatest emphasis is usually on the more completely specified and contractual forms.

The Southeast Region Task Force defines a power pool as "any two or more interconnected electric systems with coordinated planning and operation so as to supply power in a reliable and economical manner for their combined load requirement and maintenance program."

The definition encompasses coordination for purposes ranging from short-term emergency outages, medium-term power exchanges to facilitate maintenance, and economy interchanges--all on a simple bilateral basis--to

long-term centralized planning and coordination of all facets of electric power system operation within multilateral agreements, including holding company corporate structures. The broadness of the definition reflects the diversity of utility experience and practice among the task force members, and their belief that effective discussion of pooling issues and problems requires such a broad definition.

CHARGE TO THE TASK FORCE

The specific charge to the task force was to describe and explain the state of coordination within the region, including regional characteristics influencing coordination and pooling, to provide a factual basis for the Commission's evaluation of available pooling benefits. The task force was asked to identify the benefits currently achieved from existing coordination patterns, benefits prospectively available from further coordination, actions underway and planned which could result in better coordination, and impediments to additional coordination and pooling.

To support an understanding of the regional coordination and pooling situation, the task force was asked to provide in its report a summary description of relevant regional electric characteristics, including loads, energy sources, transmission maps, and unique regional features, such as the peninsular character of Florida and the special character of the federally owned Tennessee Valley Authority system.

STUDY AND REPORT PLAN

The task force members attended five full-day meetings. In addition to participating in the general discussions, some members prepared working papers addressing the characteristics and problems of coordinated electric power operations in their designated areas. The working papers are presented, essentially unchanged, in the later chapters of this report under their respective subregion headings. The regional report was drafted by the Federal Energy Regulatory Commission's (FERC) regional office staff, utilizing the information developed in the meetings, the working papers prepared by the task force members, and other appropriate information from the Commission files. The drafts were reviewed by the task force to ensure that the report properly reflected their knowledge of the regional situation, and the final draft was further reviewed by the Southeastearn Reliability Council (SERC), the State regulatory bodies, and some industry trade associations.

EXISTING COORDINATION PATTERNS

Much of this report is concerned with providing an adequate base of understanding of the existing degree of electric power coordination in the Southeast Region, and of the factors that have shaped those patterns. Such an understanding is clearly fundamental to any assessment of possible improvements.

COORDINATION ISSUES AND PROBLEMS

The task force report also discusses the various concerns, forces, and constraints that may help or hinder coordination in the region, such as common vulnerability to fuel supply, Federal power programs, holding company groups, differing State regulatory practices, utility management imperatives, and financing. It specifically addresses the comparative problems of loose coordination versus tight coordination, the issue of including smaller systems in pools, and the attitudes of utilities toward improved coordination.

ASSESSMENT OF COORDINATION POTENTIAL

The task force report provides an assessment of the prospects for increased power pooling in the region and subregion. The assessment includes consideration of such topics as the basis for coordination in current use by coordinating groups, i.e., whether they operate as a coordinating group for planning purposes only, operate with completely automatic central dispatch, or at some point between these extremes.

The report includes a brief discussion of the feasibility and merit of the integrated operation of the entire region or subsets thereof as a single, fully coordinated, centrally dispatched power pool.

CRITICAL FACTORS IN ACHIEVING COORDINATION POTENTIALS

The task force report identifies and addresses in its Report the requirements or necessary events it believes must occur in the Southeast Region to increase significantly the extent and benefits of power pooling. These events include such things as State actions, utility actions, settlement of legal proceedings, completion of joint studies and accelerated siting or other regulatory decisions, e.g., reduction in lead time form decision commitment to commercial operation.

REPORT RESPONSIBILITY

The task force report is intended to provide information on coordination and pooling in the Southeast Region. It reflects the combined knowledge of the task force members, but differences of view between members exist on a number of topics. The report does not attempt to hide the differences. Although the differences may not be explicitly identified in all cases, the context of the report should make them evident in most cases. The information and views expressed in the report are those of the task force, and not necessarily those of the Federal Energy Regulatory Commission.

CHAPTER 2
REGIONAL CHARACTERISTICS AFFECTING POOLING

DESCRIPTION OF THE SOUTHEAST REGION

The progression of electric power transmission system interconnection in the Southeast Region is shown in the sketches in Figures 2 and 3 which depict the change from 1949 to 1977 in transmission facilities at 115 kV and above. Table 1 provides information on the electric power characteristics of the Southeast Region and its four subregions with regard to peakloads, generating capability at the time of peakload, and the major intraregion, and interregion and subregion interconnections. Appendix C provides the same information by company.

The Southeast Region includes the entire States of North Carolina, South Carolina, Georgia, Florida, Alabama, and Tennessee, and portions of Virginia, Kentucky, and Mississippi, as shown in Figure 1. The region's area is approximately 350,000 square miles and the current population is over 35,000,000. The region is characterized by hot summers with average summer temperatures ranging from 84°F in southern Florida, to 77°F in Kentucky.

The region's winters range from a mild 76°F average in southern Florida to a very cold 36°F average in Tennessee. The entire region normally has abundant runoff conditions with average annual rainfall varying from 70 inches in the South Carolina mountains to 45 inches in northern Tennessee. The terrain varies greatly throughout the region. The northern portions of the region are characterized by mountains with heavy vegetation. The coastal area of the region has rolling terrain with moderate vegetation. The southern area (including the Florida peninsula) is relatively flat with considerable marsh and swamp conditions.

Major population centers are scattered throughout the region. All of the States in the Southeast Region except Alabama and Mississippi have experienced at least a 22-percent increase in population since 1960. Florida, the most populous State in the southeast, has shown a 73-percent increase in population since 1960, the largest increase in the region. Mississippi and Alabama have shown increases of 10 and 14 percent, respectively, the smallest increases in the region. However, the rate of growth has declined throughout the entire Southeast in the last 5 years.

In the last 30 years, manufacturing has grown much faster in the Southeast Region than in the northern region of the Nation. The manufacturing growth, in most cases, has occurred where the major population centers are located. The notable exception is Florida, where the majority of the population growth has been the result of increased tourism, recreation industries, and retirement communities.

FIGURE 2--Transmission Interconnection Network in 1949

GENERATION CHARACTERISTICS AND PATTERNS

For the 1979-88 period, the aggregate peak electric load growth for the Southeast Region is forecast to average 5.4 percent per year, reduced from last years's forecast of 5.9 percent. To meet current peakload projections, approximately 62,600 MW of new generating capacity is either under construction or planned by SERC members of the Southeast Region during the

FIGURE 3--Transmission Interconnection Network in 1977

next 10 years. About 36,500 MW (60 percent) of this amount is nuclear generation, reflecting the heavy commitment of the Southeastern Electric Reliability Council (SERC) members in the Southeast to nuclear power.

Assuming that planned generating capacity additions are completed on schedule, reserve margins in the four subregions--Florida, Southern, Tennessee Valley Authority (TVA), and Virginia-Carolinas (VACAR)--should be adequate for the 10-year period, provided electric loads do not increase to

TABLE 1--Electric Power Chara

Name	Code	Generating[1] capability 1978 MW
Southeast Region		109,038
Subregions		
Florida		22,426
Southern		24,827
Tennessee Valley Authority		26,426
Virginia-Carolinas		35,361

[1]Capability and peakload values taken from Generating Capability and Fossil Fuel Require Electric Reliability Council.

[2]Abbreviations are from "Plant and Ownersh DOE/EIA-0057.

cteristics--Southeast Region

Peakload[1] 1978 MW	Major interconnections[2] for bulk power transactions
81,533(S)	APPC, ARPL, CEIP, EAKR, ELNE, ILPC, KEPC, KEUC, LOGE, LOLP, MIPO, MOPC, POEC, POEP, UNEC.
16,867(W)	ALAP, ALEC, GEPC.
20,297(S)	DUPC, FLPC, FLPL, LOLP, MIPO, SAEP, SOCG, TEVA.
21,540(W)	ALAP, APPC, ARPL, CAPO, CEIP, EAKR, ELNE, GEPC, ILPC, KEPC, KEUC, LOGE, MIPO, NAPL, UNEC.
26,391(S)	APPC, GEPC, MOPC, POEC, POEP, TEVA.

"Summary of Projected Peakloads,
ments--1979," published by the National

ip List--1978," Department of Energy,

levels above those projected. However, the questionable ability of the utility systems to maintain the planned capacity additions on schedule, particularly the extensive nuclear program, is cause for concern. Recent evidence suggests that some systems are modifying their reported generating capacity addition schedules by delaying certain units.

Considering current load forecasts, and the potential for slippages in the currently planned generating capacity schedules, the Southeast Region systems could face a degradation of system adequacy. By 1988, a potential load reduction of between 10,000 to 15,000 MW may be required to provide an acceptable degree of adequacy within the SERC members of the Southeast Region.[1]

The Florida systems are concerned about their ability to meet Florida's opacity and particulate emission standards continuously. This concern is heightened by the mandatory penalities described by the 1977 Clean Air Act. As a result of the emergency created by the current low-sulfur fuel oil shortage, emission standards for some Florida utilities have been temporarily relaxed since April 1979 under the emergency procedures provisions of the Clean Air Act. However, this reprieve can only be granted for a maximum of 4 months. In an effort to obtain a permanent solution, Florida systems have had a hearing before the Florida Department of Environmental Regulations to review Florida's opacity and particulate standards. A favorable result from this hearing would permit compliance with the standards without compromising power supply capabilities and should alleviate the fuel oil procurement difficulty.

The TVA, VACAR and Southern Subregions have developed a strong internal transmission system that is highly interconnected with the adjacent council regions of the Southwest Power Pool (SPP), the Mid-America Interpool Network (MAIN), the East Central Area Reliability Coordination Agreement (ECAR), and the Mid-Atlantic Area Council (MAAC). Joint studies between SERC members of the Southeast Region and these adjacent council regions are made continually to assess the adequacy and reliability of the interconnected network. Transmission in the northern part of Florida is relatively weak, but plans are underway to strengthen this area.

Factors that affect the proposed construction program in the Southeast Region are similar to those that affect other systems, e.g., adequate and timely rate relief, and timely issuance of construction permits and operational licenses.

The location and type of the generating stations presently in the Southeast Region depend on the characteristics of the subregion under consideration. The Florida Subregion's geographic feature of being a peninsula weighs very heavily on the fact that in 1979 over 75 percent of the generating capacity was oil fired. However, because of the emission standards in Florida and scarce supplies of low-sulfur oil, there is a continued swing away from oil toward low-sulfur coal. In 1979, 13 percent of the generating capacity in Florida was produced using nuclear fuels, 9 percent using coal fuels, and less than 1 percent was produced by hydroelectric facilities. In the Southern Subregion (southeastern Mississippi, southern four-fifths of Alabama, the Florida Panhandle, and Georgia), 67 percent of generating capacity was produced by coal-fired plants, 9 percent by nuclear plants, 2 percent by natural gas-fired plants,

10 percent by oil-fired plant, and 12 percent by hydroelectric facilities. In the VACAR Subregion (North Carolina, South Carolina, and the eastern three-fourths of Virginia), 49 percent of the generating capacity was produced by coal-fired plants, 21 percent by nuclear plants, 20 percent by oil-fired plants, and 10 percent by hydroelectric facilities.

In the TVA Subregion (Tennessee, northern Alabama, northeastern Mississippi, southern Kentucky, and small portions of Georgia and North Carolina), 63 percent of the generating capacity was produced by coal-fired plants, 12 percent by nuclear plants, 9 percent by oil-fired plants, and 16 percent by hydroelectric facilities. The amount of coal reserves and the availability of water supplies in the Southern, TVA, and VACAR Subregions are two major reasons that these areas produce such a high percentage of their electrical capacity needs with coal. The reliance on coal for electrical generation, in view of the attitudes on nuclear fuels, could increase significantly in the future.

BILATERAL AGREEMENTS

Interconnected utilities generally initiate coordination at the time of interconnection, through bilateral agreements covering such transactions as emergency puchases, fixed-term capacity and energy purchases, economy energy exchanges, transmission service, coordination of maintenance outages, and other matters. As these agreements are modified and expanded to cover more situations and new interconnections, they become an operating framework for coordination of operation and planning between groups of utilities. Because it is easier to administer two-party agreements than multiparty agreements, the bilateral agreement is the predominant contract form used in coordination and has proved to be flexible and effective over a considerable range of situations. However, where there are extensive daily interchanges between a number of utilities, the desirability of uniform transmission charges and standardized methods for calculating rates can make multiparty agreements desirable.

Generally, all agreements and changes to existing agreements involving a privately owned utility must be filed with FERC and are subject to its approval. Under FERC rules, other parties may challenge any agreement on the grounds of whether it is just and reasonable or whether it represents anticompetitive behavior.

COORDINATING MECHANISMS OTHER THAN POWER POOLS

Power pooling is based on interconnected operation of power systems. For many years, the technical requirements of interconnected operation have brought utilities together to establish standards and criteria for equipment and operating practices. Two major organizational structures have been used by the industry to achieve technical coordination: the North American Power System Interconnection Committee (NAPSIC) and the Regional Reliability Councils. (See Figure 4.) The Southeastern Electric Reliability Council (SERC) is one of the nine regional councils. The National Electric

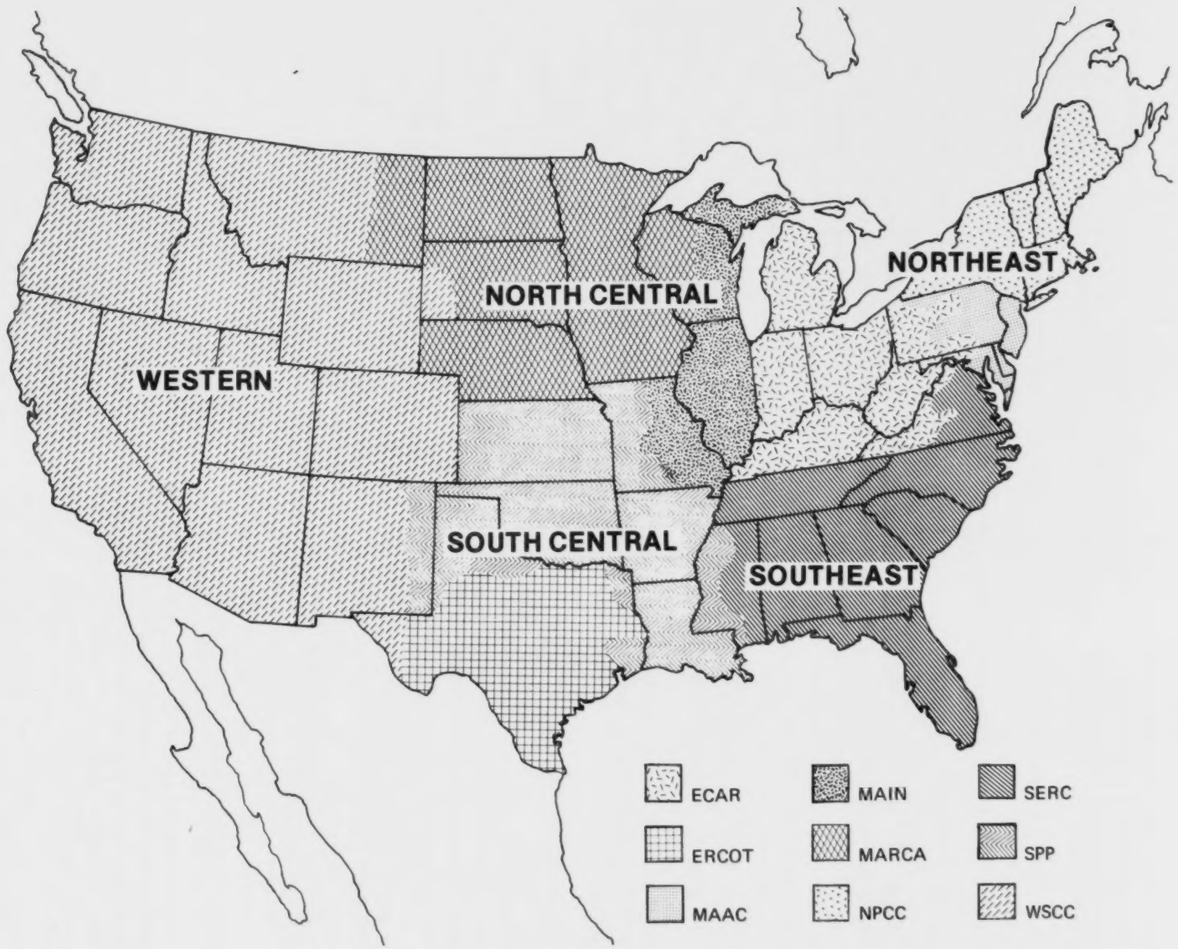

FIGURE 4--The Nine Regional Areas of the National Electric Reliability Council and the Five Task Force Regions

Reliability Council (NERC) was established by the industry as a forum to address national and interregional issues.

These industry technical coordinating mechanisms play an important role in the overall coordination and power pooling of utility systems. The following discussion provides background information on NAPSIC, SERC, and NERC.

NORTH AMERICAN POWER SYSTEM INTERCONNECTION COMMITTEE

In April 1962, representatives of interconnected systems throughout the United States and eastern Canada met at Omaha, Nebraska and laid the groundwork for an international organization to coordinate the technical requirements for operation of a coast-to-coast interconnected network. This meeting led to formation of NAPSIC, which held its first meeting in January 1963. NAPSIC is a voluntary organization of operating personnel representing 11 interconnected operating areas.

At the outset, the principal goals of NAPSIC were to coordinate frequency, operating criteria related to time error, and tielines bias settings. Its first operating manual was published in September 1964. By January 1968, the number of guides included in the Operating Manual had increased from 9 to 20. The guides establish general criteria which, although not explicit enough to be used as detailed specifications for system operation, enunciate generally accepted principles and codify minimum operating criteria for coordinated operation.

As the regional reliability councils developed, their planning activities overlapped more frequently with the operation activities of the various areas within NAPSIC. Close working relationships between these different organizational units provided the opportunity for effective coordination between planning and operating functions, but the evident overlap caused the industry to examine combining NAPSIC with NERC. During 1978, NAPSIC-designated representatives met with NERC representatives to develop a plan for merging NAPSIC and NERC. The year 1979 was considered a test year in which NAPSIC would respond as though it were part of NERC to accomplish its tasks in its standard manner. During this test year, final arrangements were expected to be made for a new NAPSIC organization within NERC and a new statement of responsibilities. (These arrangements became effective on January 1, 1980.)

NATIONAL ELECTRIC RELIABILITY COUNCIL

Formed voluntarily by the electric utility industry in 1968 and incorporated in 1975, NERC has directed its efforts to augmenting the reliability and adequacy of bulk power supply for the electric utility systems in North America. NERC is a national organization formed by the nine regional councils whose memberships comprise essentially all electric utility systems in the United States and the Canadian systems in Ontario, British Columbia, Manitoba, and New Brunswick. NERC is not a governing organization for the regional councils but rather a consortium of the regional councils focusing on interregional and regional electric reliability issues.

The governing body of NERC, the Board of Trustees, consists of two representatives of each regional council, plus such additional members as are necessary to ensure at least two representatives from each segment of the electric utility industry; i.e., investor-owned, Federal, Rural Electric Cooperative, and municipal-State.

Meetings of the board are attended by observers designated by the Secretary of the U.S. Department of Energy and the chairman of the National Energy Board (Canada).

The nine councils encompass the entire electric utility industry, both investor-owned and publicly owned. Their mission basically embraces only technical matters; their primary objective is to augment or protect reliability and adequacy of the bulk (electric) power supply in highly interconnected transmission networks in the United States and four Provinces of Canada.

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

Membership in SERC, formed on January 15, 1970, is open to all power utilities interconnected with the regional electric network and operating a generating capability of 25 MW or more.

The executive board, consisting of one representative from each member utility, conducts the affairs of the Council. Voting rights and expenses are allocated in proportion to generating capability. An administrative manager has been retained since January 1, 1971.

Eight associated members represent distribution cooperatives and municipalities operating either no generation or less than 25 MW.

The objectives of SERC are to establish reliability criteria of the bulk electric power supply of the region. The four subregions implement the reliability guidelines through coordinating mechanisms designed to achieve optimal economics of operation.

Members observe guidelines that include criteria for reliability in system planning to minimize the possibility of cascading outages of bulk power supply resources and facilities, and criteria for reporting loads and the rating of generating units on a uniform basis.

SERC has a Technical Advisory Committee consisting of a member and an alternate from each member system. Task forces are appointed as needed for specific projects. Representatives from Federal and State commissions are invited to attend all council meetings, as well as meetings of the Joint Executive Committee.

The four subregions of SERC are the Florida, Southern, TVA, and VACAR Subregions. Liaison with NAPSIC is done through the chairman of the Southeast Region of NAPSIC and the SERC Technical Advisory Committee. Other SERC liaison representatives monitor and promote coordination of reliability with the adjacent councils. A degree of effective coordination is obtained at the subregion level. Within the subregions, the TVA and the Southern electric system each operate with a single control area, VACAR operates with six control areas and Florida operates with eight control areas.

As of 1978, approximately 165 people were involved in SERC activities. Through the different SERC committees and coordination with other NERC members, the SERC membership has set the guidelines for uniform load

forecasting methods, uniform rating of generators, and the criteria for system reliability studies. The SERC committees also monitor and report on various factors that affect the utility industries in the Southeast Region, such as availability of fuel supplies, major outages that might occur, coordinated bulk power supply programs, and events occurring outside the SERC area that will affect the reliability of the Southeast Region.

UTILITY OWNERSHIP PATTERNS

The private investor-owned utilities produce more than 95 percent of the electrical capacity in the Southern and VACAR Subregions. The remaining electrical capacity is produced by the consumer-owned utilities and the public utilities. In the Florida Subregion, approximately 80 percent of the power is produced by private investor-owned utilities. The public utilities produce approximately 19 percent of the Florida Subregion's need, and the remaining needs are produced by consumer-owned and government utilities. Recently in the Florida, Southern, and VACAR Subregions, generating plants jointly owned by investor-owned utilities and public- or consumer-owned utilities have been completed; others are under construction, or are in the planning stages. In the TVA Subregion, all but a small fraction of the electric generating capacity is produced by TVA.

STATE REGULATORY BODIES

Each State in the Southeast Region has a regulatory commission. The authority exercised by these commissions is discussed in Chapter 4. Regulatory authority over power interchanges involving jurisdictional utilities is exercised by FERC.

The Southeast Region State regulatory commissions differ considerably in the size of their staffs and budgets, and scope of their research capabilities and statutory responsibilities in the Southeast Region. As an example, The State Regulatory Commission of the State of Florida, (population 8,549,000) has a 1979 budget of $9.9 million, a professional staff of 189 and a total staff of 430; it performs research functions and uses computer facilities to assist in its operations. The State Regulatory Commission of the State of North Carolina (population 5,570,000) has a 1979 budget of $4.3 million, a professional staff of 64, and a total staff of 160; it performs research functions, and uses a computer in its operations. The State Regulatory Commission of the State of Georgia (population 5,084,000) has a 1979 budget of $2.7 million, a professional staff of 39, a total staff of 106, and does not perform research functions or use the computer in its operations. Alabama and Georgia select their Commissions by election. The remaining States, which are entirely in the Southeast Region, select their Commissions by appointment. North Carolina has taken action to study and promote load management with the purpose of reducing electric demands during peak periods. Such additional investigations, beyond the rate regulating that some of the State regulating bodies are performing, started several years ago as a result of the significant increase in inflation-induced rate-hike requests made by the electric utilities in the Southeast Region.

POWER POOLING HISTORY

The events contributing to the formation of today's power pooling organizations in the Southeast Region can best be explained by the histories of the four subregions.

TENNESSEE VALLEY AUTHORITY SUBREGION

The TVA is a corporation created by an act of Congress on May 18, 1933. TVA is wholly owned by the U.S. Government and its electric power program is required to be self-supporting. TVA presently supplies wholesale power to 160 local municipals and cooperatives in all or part of six States.

Although TVA is not made up of several companies, it can be considered a pool in that it is centrally dispatched and controlled, operates from five dispatching areas, and is interconnected at 30 points. Over the years, TVA has established interconnection agreements with contiguous utilities for economic energy exchange, increased reliability, and seasonal energy exchanges.

SOUTHERN SUBREGION

In the Southern Subregion, the history of pooling started with the private utilities in 1912. The first interconnection of two major systems (Alabama and Georgia) occurred in 1920. As a result of several legislative and judicial events between 1920 and 1947, the Southern electric system was formed with its present-day subsidiaries. (See Chapter 6.) (Note: Southern Company is a holding company.) The evolutionary growth of this holding company has resulted in closely coordinated operations among its subsidiaries, a highly centralized planning organization, and the establishment of interconnections with utilities outside the holding company's area.

In 1944, the Alabama Electric Cooperative was established. This organization has provided coordinated operation among its 20 members in Alabama and Florida. It has also entered into coordination agreements with a subsidiary of the Southern electric system.

In 1975, the Municipal Electric Authority of Georgia (MEAG) was established by the Georgia Legislature. This organization provides power to 40 municipalities and one county in Georgia. MEAG has also entered into joint operation with a subsidiary of the Southern electric system.

FLORIDA SUBREGION

The primary pooling organization in the Florida Subregion is the Florida Electric Power Coordinating Group, Inc. (FCG). The FCG was started in 1959 as the Florida Operating Committee, consisting of three utilities. (See Chapter 7.) Between 1959 and 1972 the Florida Operating Committee increased its membership and developed procedures for reliability. In 1972, the utilities who were members of the Florida Operating Committee established the

FCG and opened membership to all Florida utilities. In 1979, FCG membership consisted of 37 investor-owned, municipal, and cooperative utilities. The evolution of the FCG has resulted in the establishment of an energy brokerage system in Florida and studies aimed at finding more efficient methods to provide electrical energy to the Florida consumer.

In 1978, FMPA was created. This organization, made up of 26 municipal systems in Florida, is presently negotiating for joint ownership in several generating plants and is involved as an entity in studies with the FCG to consider several different transmission and generation supply alternatives for its members.

The Seminole Electric Cooperative, which is a member of FCG, is an 11-member generation and transmission cooperative formed in 1948 to handle rate negotiations for purchased power. Because of uncertainties of future supplies, Seminole has obtained, or is negotiating for, joint ownership in several generating plants and is committed to constructing generating units to supply at least half of its electrical needs.

VACAR SUBREGION

The VACAR group is an organization of six utilities that was formed as a result of the breakup of the formal contractual power pool CARVA. CARVA was formed on July 1, 1961 by four of the present VACAR companies (see Chapter 5 for organizational members). The members of the CARVA pool experienced several operational and institutional difficulties that resulted in the termination of the CARVA Pool on April 30, 1970. In 1971, the VACAR group was formed and it established an Executive Committee that was responsible for the operations and planning functions of the VACAR members. The companies in VACAR have established internal agreements for interconnections, with improved economy of operations and increased reliability as the major objectives. Over the years, the VACAR members have also established interconnections with several contiguous utilities.

COMPETITIVE SITUATION

The electric utility industry in the Southeast Region, like the remaining sections of the United States, is a mixture of investor-owned utilities, consumer-owned utilities, and public utilities. Historically, these groups have competed for unclaimed service territories. In recent years, as electrical service has approached 100 percent, some of the intensity of competition has abated. For the most part, the existing competition is not for unclaimed loads, but centers around the differences in the institutions; thus, ideological differences and mistrust from the past still exist to a moderate degree. Considerable efforts have been made by these groups recently for joint utility planning and operation, but these efforts have not been automatic or without conflicts. Additional discussion regarding joint planning efforts and problems is offered in Chapter 3.

REFERENCES

[1]National Electric Reliability Council, "9th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," August 1979.

CHAPTER 3
POOLING BENEFITS, ISSUES, AND PROBLEMS

The material in this chapter is based on information provided by task force members in response to a series of questions relating to the benefits, issues and problems of power pooling in the Southeast Region. In many cases direct quotations are cited in quotation marks, but specific credits have not been made.

BENEFITS

Pooling activities, such as coordinated electrical operations or contractual pooling arrangements, may provide the participating electric utilities the opportunity for improving their economics and resources utilization. In some of the subregions of the Southeast, capital savings have been achieved by installing larger units, thus taking advantage of the economies of scale. Savings have also been realized within the subregions by sharing reserves, reducing the need for facilities to provide the subregion's overall reserve.

RESERVE CAPACITY

The member companies of the Southern Company in the Southern Subregion have stated that their operating independently would probably require each company to provide operating reserves equal to at least its largest unit installed. This would result in an online reserve capacity of 2760 MW. As members of a pool, the individual companies would be required to share the reserve requirement equal to 1.5 times the largest unit in the pool. This results in an online reserve capacity of 1320 MW, an estimated savings of $17.3 million per year.

The Virginia-Carolinas (VACAR) Subregion's operating task force has developed workable agreements among their members through which sharing of spinning reserves has significantly reduced the required reserve margin of each system in VACAR.

The operating committee of the Florida Electric Power Coordinating Group (FCG) has developed procedures for establishing and administering the daily operating reserves (spinning reserve plus supplemental reserve) for the 13 electric generating utilities in the committee. Sharing of this daily operating reserves by all operating committee members lowers the operating costs through more economic allocation and dispatch of units and reduces the online capacity requirements.

COST SAVINGS

Interregional and intraregional coordinated electrical operations have resulted in economic and resource savings through economy interchanges, diversity of peakloads, and seasonal exchanges. The Southeast Region has two subregions that are winter-peaking (the TVA and Florida Subregions) and two subregions that are summer-peaking (the Southern and VACAR Subregions). Numerous coordination agreements between companies within different subregions and companies outside the Southeast Region have been established because of the seasonal exchanges (winter-summer peaking), economy interchanges, and diversity of peak loads. The Southern electric system estimates an annual cost savings of $8.3 million because of its seasonal exchange contract with TVA. In fiscal year 1978 TVA has estimated a total operational cost savings of $29.0 million because of its interconnection transactions with neighboring utilities. This savings does not involve benefits derived from diversity exchange and certain other emergency exchanges. The FCG has established an energy brokerage system where members of FCG can easily take advantage of the differences in incremental costs among the FCG members. The current annual savings from these economy interchanges are estimated at $22.0 million per year. The VACAR group has also established practices that assist their members in the maximum transfer of economy energy and resultant savings to all of their companies. VACAR has estimated total benefits from interchange agreements to the members of the reliability group for 1978 to be $9.1 million.

RELIABILITY

The utilities in the TVA, Southern, Florida, and VACAR Subregions have also realized benefits from the established electrical coordinating agreements as a result of emergency exchanges and reliability benefits. It is difficult to place a dollar value on the benefits of reliability, as in avoiding a cascading blackout. It is also difficult to quantify all the benefits of emergency exchanges. The Southern electric system estimates an annual capital cost benefit of $2.3 million, because with each company operating independently the emergency capacity available to each company would be less than that available to the pool, due to tieline restrictions and reduced diversity and access with neighboring companies.

ISSUES AND PROBLEMS

Although the concept of power pooling is generally accepted as a means for obtaining the benefits of conservation of energy, economy, and reliability, differences exist regarding the optimum scope and structure of the associated administrative vehicle or pool. The evolution of the varied stages of pooling exhibited by the four subgroups of the Southeast Region reflects many of the issues and problems inherent in the pooling concept. The technical, institutional, legal, and financial considerations discussed

in this report have contributed to the present status of pooling in the Southeast Region.

The possibility of a single, regionwide, fully coordinated, centrally dispatched power pool suggests a number of problems and complications. If the regional pool being considered will have responsibility for the planning, financing, and development functions as well as an operating function, several points must first be considered. In the investor-owned utility segment of the Southeast, the typical electric utility exists under the supervision of a particular State's regulation and has legal obligations to a particular constituency that it serves as a public utility. Such a utility is typically required to obtain State approval of its capital structure, its issuance of securities, the plants it will be authorized to construct and own, and, perhaps most importantly, the level of its rates. Thus, in a sense, everything a particular utility desires to do must first be settled with its own constituency and State regulations, including demonstration that what it does will be acceptable to, and for the benefit of, those who invest capital in its utility plant as well as the rate payers who bear the ultimate burden of capital commitment. These responsibilities, obligations, and controls make it difficult for any particular company to become involved in a single regionwide pool, the governing body of which would have authority to commit it to development of plant, (generating facilities or transmission lines), until the matter has been fully approved at the local level. The comments with respect to the investor-owned utilities are also applicable to the public power systems in the Southeast in that they too must first settle with their constituency and regulatory body.

Before a determination could be made on the magnitude of additional transmission needed in the Southeast to accomplish a regionwide pool, extensive studies would have to be completed. Apparently a large amount of funds would be required to fully integrate all electric plants in the Southeast.

A special consideration affecting size arises when considering regionwide pooling within a system regulated under the Public Utility Holding Company Act. In connection with the Securities and Exchange Commission (SEC) approval of the creation of the Southern Company under the Public Utility Holding Company Act, the SEC held that under the size standards embodied in the Holding Company Act, the area served by the present operating companies of the Southern Company was the maximum allowable under one ownership. As a part of such approval, the SEC refused to allow inclusion of properties in South Carolina, and required divestiture. Such approval was granted only upon a finding of integration of facilities and coordination of planning and operation of systems; therefore, on the basis of the history of this case, the SEC probably would not permit expansion of such an integrated operation. The SEC has not raised objections to certain coordinated operations with other utilities in the Southeast.

Whatever additional savings are not being realized but might be gained are difficult to determine. In many instances, economies of scale in generation are already being achieved within pools or single systems. The potential savings associated with available seasonal capacity exchanges are nearly exhausted. Economy energy transactions are reducing significantly the

use of petroleum fuels within subregions. To increase such transactions in the future, long-range utilization of committed facilities and fuels must be consigned. This approach will necessitate different rate structuring to cover the costs to the supplying system and allow adequate planning for fuel supply.

A general observation is that pooling arrangements require unanimity among participants to achieve the objectives sought. Such unanimity is difficult to achieve, even in holding company arrangements. Evaluating benefits and detriments and reaching unanimous agreement is easier when only two parties are involved than when many parties are involved.

TECHNICAL FACTORS

In a theoretical sense, optimum pooling would entail central generation dispatch and integrated capacity planning of an optimized size pool. However, many practical factors restrict accomplishment of such a pool.

The general consensus of the task force throughout the Southeast Region is that the determination of optimum size is at best very difficult, if possible at all. Such factors as load density, availability of resources within an area, geographic features, location with respect to neighbors, and number of individual utilities affect the optimum size of a power pool. Hence, an optimum size can only be determined on a specific pool basis.

Initiating central dispatch or formally coordinated capacity planning generally requires a complex agreement defining types of transactions, fuel commitment, transmission system access and pricing, capacity obligations and payments, transmission adequacy, incremental and decremental costs, operating procedures, cost and benefit allocation methods, pool facilities, and other such complicated factors of electric power system operation. Central dispatch requires development of an agreement acceptable to all member companies and sufficiently flexible to respond to changing conditions in a timely manner.

In areas where major differences exist between system peakloads and load diversities, and in transmission system configurations and design philosophies, achieving a group consensus and developing an agreement that can survive the changes of time are difficult tasks.

Engineering judgment also varies on the need for formal centralized pooling to achieve the benefits of pooling. Some suggest that the application of appropriate bilateral agreements can achieve reliable and coordinated economic operation without the increase of complexity and loss of autonomy inherent in formal multilateral agreements.

The effects of increased coordination on the reliability and economcs of an involved system can also be negative. One system integrating its operations with a group wherein members of the group are having major construction, fuel, and financial problems could contribute more benefit to the overall pool than it receives. Where the group transmission network and operating procedures are not equivalent, reliability can suffer. Such factors are major considerations in any contemplation of increased pooling.

The benefits realized to small systems stem principally from the adequacy of the available power supply and system reliability. A small system

interconnected with a large system is reasonably sure that it can receive from the large neighbor sufficient energy during an emergency to meet its needs adequately. The large system, on the other hand, cannot be assured of receiving an adequate supply of energy from a small neighbor, should an emergency occur on the large system. The ownership of the system would not be a factor; the benefits accrue from relative size.

INSTITUTIONAL FACTORS

Legislation regarding the electric utility industry has historically mandated a pluralistic ownership structure and has resulted in public power systems providing a semblance of competition in a regulated industry. The introduction of competition while trying to foster increased pooling generates questions that tend to interfere with attempts to reach mutually satisfactory pooling arrangements. Coordination and competition are concepts that are, in most instances, opposites. However, coordination does exist on a sophisticated level among public and investor-owned utilities. The arrangements between TVA and the private sector provide a high degree of coordination that is beneficial from an economic as well as a reliability standpoint. Similar coordination has been conducted with cooperative and municipal entities having generation. The degree of coordination has varied according to the particular circumstance and the perceived impact that such coordination would have on the cost of providing service to the customers of the systems involved.

Utility systems are generally able to negotiate pooling coordination arrangements notwithstanding differences in ownership and character of the component systems. However, issues may arise between systems in the following situations:

- Two utilities have planned and committed their plant facilities to serve the same projected loads.
- One power system seeks to use the plants and facilities of another power system to back up or support construction of its own facilities or seeks to acquire some fractional part of an existing system when the only economic saving is the substitution of tax-exempt bonds and tax immunities for its conventional financing and associated tax obligation.
- In joint planning proposals, the first power system seeks to obtain ownership participation in the facilities of the second system and proposes to use these facilities in a competitive manner which will alter the economic basis on which the second power system financed and developed the system.
- Joint planning and ownership of generating plants are proposed and the cost of capital to all participants is not equal. The organization with the lower cost of capital will tend to favor installations with higher initial costs and lower operating costs, and the organization with the higher cost of capital will tend to favor the converse.

At the foundation of a comprehensive pooling arrangement is the imperative of valid planning. Valid planning means that each participant

must be able to project with confidence the anticipated loads to be served by the pooled electric generating plants and related transmission lines. Among competitors for the same loads, this projection would be difficult if not impossible.

For small utility companies that have operated as full or partial requirement customers, overcoming some of the built-in thought processes and negotiating without the dominance of the supplier-customer relationship are difficult undertakings. This difficulty is exemplified by written contracts in which the only recourse for specific performance is the court system. Transmission arrangements and operating procedures may not provide small systems an access to the type of power pooling exchanges desired.

Different management perceptions of pooling alternatives can lead to different conclusions regarding the appropriate organizational structure for a pooling arrangement.

The failure to formulate the Carolinas-Virginia (CARVA) pool was the result of institutional differences that could not be resolved. Owing to the considerably different characteristics of the four systems involved, their relative sizes, and the geographic distribution of load centers, each system was designed within parameters best suited for that type of system, and no common ground was found that was equitable for all systems.

Where the essential benefits of pooling can be achieved without a formal pooling structure, e.g., reserve sharing and economic energy interchange, a system can hardly justify entering into a formal pooling agreement solely for the sake of pooling.

LEGAL FACTORS

Where the concept of power pooling involves more than one State, State regulations and philosophies of regulation can differ. Likewise, various Federal agencies that affect the electric utility industry also have different objectives. Both situations can inhibit the benefits of power pooling.

Power system regulators are required to promote adequate, economical, and reliable electric service. Power pooling can both help and hinder each of these objectives, and the circumstances and the perceptions of the regulator can affect the pooling.

The following statements are direct quotations provided by the task force members in response to the written request, "Identify impediments and deterrents to pooling coordination of a legal/regulatory character including any conflicting State regulatory policies and any adverse effects of FERC regulatory policies."

> State regulators can encourage utilities under their jurisdiction to form operating pools with other utilities, but are usually reluctant to do so if reliability suffers, service quality suffers, or the utilities do not gain a proper share of the benefits. Pooling arrangements should not inhibit the planning of individual utilities for future service systems because the individual utilities are

responsible to regulators for adequate service. Individual utilities should construct adequate facilities to ensure continued economical service if the pool is dissolved. Pooling contracts must allow regulators to examine and determine the flow of benefits in costs as well as in service quality and reliability, and such considerations add to the complexity of pooling. Alternate methods of negotiating power transfers need to be considered so that receiving utilities can contract directly with sending utilities without a chain of two-party contracts from contiguous utility to contiguous utility. In exploring such transactions, however, the adverse impact on intervening utilities, plus the identifiable costs of such transactions, must be considered.

Contracts for purchased power must be beneficial to ratepayers, else regulators will not allow such contracts. Pricing methods must ensure that middlemen in multiutility transfers are paid charges commensurate with their services.

Excessive profits to middlemen could decrease savings to companies separated by one or more intervening utilities. Energy charges and transmission use charges must accurately reflect the impact on each company involved. Purchasing is not economical if intervening utilities impose such transfer charges that the receiving utility can no longer afford to accept a transfer when, by lowering the charge, the transfer would be beneficial to all utilities.

A sending utility should not be allowed or required to use its fuel stocks (especially nuclear) unless compensation is sufficient to cover the replacement cost of those stocks.

* * *

Coordination among entities engaged in the same line of business is generally suspect under U.S. antitrust laws. The greater such coordination becomes, the more likelihood that businesses may run afoul of those laws. Maximum coordination in the electric utility industry would involve not only operational coordination, but also coordination of planning to the end that suppliers would reduce the facilities constructed to only a single set of optimum size facilities to meet the jointly projected load to be served. To achieve such objectives, the participants must reach agreement on the loads to be served and determine which party will serve which loads in order to fix responsibility for plant investment.

Were it suggested to the nation's steel suppliers that they coordinate the construction of steel mills to reduce the economic burden of excess steel production capacity, such suggestion would be viewed as anticompetitive. When a similar question with reference to the electric utility industry was posed to the U.S. Department of Justice by the Legal Advisory Committee of the 1964 Federal Power Commission (FPC) National Power Survey, the response was equivocal and offered no comfort to potential coordinating partners in the adoption of extensive coordination. (See 1964 National Power Survey--Part II, p. 367.) This area of the law needs clarification. If the objective of pooling is to ensure a reduction of production

capability to the minimum, significant changes in the antitrust laws as they relate to the electric utility industry must be forthcoming.*

* * *

In mid-1977, three Florida utilities filed revised interchange agreements for updating and improving their existing bilateral agreements. This routine matter, upon intervention by other parties, expanded far out of proportion to the basic jurisdictional issue. The FERC staff opened the door to antitrust issues not involved in the filing of the agreements, with threats of in-depth discovery and interrogatories of parties not at issue in the intervention. The FERC personnel in the dockets were changed during the period of negotiations, a situation that caused delays and impediments to timely resolution. After 3 years of expensive, time-consuming procedures, the matter is close to being settled by an agreement among the FERC staff and the parties that there are really no issues to be decided. Such an experience has a chilling effect on the desire of utilities to coordinate or pool their facilities. Swift and unbiased due process by FERC was absent.

* * *

Coordination, whether voluntary or coerced, can only achieve its desired objectives if the coordinating partners have mutual trust and an appreciation of the abilities of the other parties. If one party seeks to reap only the benefits of coordination and uses every opportunity to undercut the other parties, no successful coordination can be achieved. This human characteristic cannot be eliminated by legislation or regulation. Where mutual trust does not exist, coordination can only be achieved through contracts in which the parties attempt to foresee all possible contingencies and address such contingencies in strict contractual language. Such a process is time consuming, and all contingencies probably will not be anticipated and included in the contract. Because of the Mobile-Sierra doctrine, which says in effect that contracts once entered cannot be amended unilaterally, even with approval of a regulatory body, the tendency is to make the term of such contracts of short duration to avoid an uneconomic situation for long periods. This tendency may affect the degree of coordination in which a party is willing to engage.

* * *

A second area of concern is the policies of FERC with respect to rates allowed on service or transactions subject to its jurisdiction. Coordination between electric utilities brings with it FERC jurisdiction over the rates for transactions conducted in coordination. To the extent that FERC's policies toward ratemaking do not allow full cost recovery, coordination becomes an undesirable mechanism if alternatives exist. For example, the policy of FERC relating to treatment of Construction Work in Progress (CWIP) is

*The legal opinions expressed here are not necessarily held by Alabama Electric Cooperative Inc.

troublesome, and to the extent an alternative exists in some States where CWIP is recognized in the ratemaking process, coordination efforts involving FERC ratemaking are less desirable.

* * *

Another example is coordination efforts such as the Yankee Companies, where FERC has allowed a return on common equity invested in those plants at the 10- to 11-percent range. Such inadequate treatment was justified on the basis of the "low risk" to the equity investor, whereas had that same investor owned the plant, the allowed return would have been 13 to 14 percent. Little incentive is created for coordination if the net result of such coordination is penalizing the participants.

* * *

Conflicting policies among governmental agencies could have a significantly adverse impact on pooling. Rigorous enforcement of the Clean Air Act, coupled with implementation of President Carter's proposed energy legislation (which would phase out oil-fired capacity) would create an environment that would discourage inclusion in any pool of those systems seriously impacted. An example is the Environmental Protection Agency (EPA) determination that Philadelphia Electric Company's Cromby and Eddystone stations are in violation of the Clean Air Act. Should Philadelphia Electric fail to reach an agreement with EPA within 30 days, those stations will be shut down. If shutdown occurs, along with Philadelphia Electric's dependence on oil, the benefits of the Pennsylvania-New Jersey-Maryland pool (PJM) would be completely negated for other member companies of the pool.

* * *

Barriers, forces, and constraints that have hindered coordination in Florida come from both Federal and State levels. At the State level, the provisions of the 1978 Clean Air Act have forced many utilities to burn low-sulfur fuel oil to meet opacity (not sulfur dioxide) limitations. This problem was only economic until the supply of low-sulfur oil became constrained during 1979. As a result of the fuel type shortages, Florida Power & Light Company (FPL) was forced to seek emergency relief from both State and Federal environmental agencies to burn a higher sulfur oil. During the time of the fuel shortages, the conditions of the emergency variances only allowed FPL to burn a higher sulfur oil to serve its own customers. Because FPL was not allowed to sell energy generated from the higher sulfur oil to other utilities, it was constrained by the environmental regulations to act principally as a buyer under the FCG Energy Broker Program.

* * *

In a positive vein, the Florida Legislature recently endorsed the concept of coordination of electric utility systems by enacting the Grid Bill and the Power Plant Siting Act. The Grid Bill expanded the authority of the Public Service Commission to include certain responsibilities to encourage and promote coordination of facilities, interconnected operation, and power exchange arrangements. The

Siting Act serves as a mechanism to coordinate the permitting process for certification of a powerplant project. It places responsibility on the Public Service Commission to certify the need for power attendant with the application. In this certification, the commission views this need for power on a statewide basis, which has the effect of ensuring that the applicant has coordinated the project in an overall State plan.

Florida State law also requires that all generation utilities submit to the Department of Community Affairs, no less frequently than every 2 years, a 10-year plan for electrical generating facilities and associated transmission lines. The Electrical Power Plant Siting Act also names the Department of Community Affairs as a statutory party in the certification of sites, thereby stressing the importance of power coordination. Overall, these laws and procedures have brought State agencies into the coordination activities with a better understanding of the broad picture.

* * *

FINANCIAL FACTORS

The basic consideration in decisions concerning coordination with other bulk power suppliers is the impact of such arrangements on the system's customers and investors. If it is clear that the proposed coordination will increase the cost of service to the utility's customers, directly or indirectly, such proposal should be rejected. An example of a direct service cost increase resulting from coordination is an obligation to purchase excess power from another utility's system whether or not such power is needed. An indirect increase in service cost could result from coordination agreements or requirements that cause the rating of the entities' bonds to be lowered because of the exposure to loss of revenue necessary to support the bonded indebtedness.

In many instances a risk has been taken by engaging in coordination, notwithstanding the exposure. In the arrangements between the operating companies of the Southern electric system and the Southeastern Power Administration (SEPA), for example, extensive coordination has been developed despite the immediate net revenue loss to the associated operating companies. However, from the standpoint of the overall arrangement, the customers of the operating companies gained the advantage of capacity made available to the operating companies--capacity that is not included in the rate base of the companies for ratemaking purposes. Thus, despite the loss of revenue associated with reduced wholesale sales, the customers of the operating companies realized a benefit from capacity, the cost of which would otherwise have been included in the rate base for ratemaking purposes.

Smaller systems appear to benefit proportionately more than large ones because of the joint planning activity and the economies of scale associated with larger units. Furthermore, any savings through exchanging economy energy, or through central dispatch, are a larger proportion of the operating expenses of the smaller utility than they are of the larger utility.

Even with agreements reached in relatively informal emergency exchanges, issues arise and their resolution influences the degree of coordination in future stages. These issues include such questions as:

- Who constructs and owns the tieline?
- What are the conditions for providing emergency power and disconnecting the tieline and load shedding?
- How should emergency power exchange be repaid?
- What are the procedures for system recovery after a disturbance?

Each question involves economic considerations which affect the financial well-being of the participants.

As the Florida electric system has evolved, FCG utilities have sought to avoid complexity by using only bilateral (two-party) agreements between utilities. Limiting the number of participants in such agreements allows maximum flexibility in resolving such issues as whether such an agreement should be renewed when it is mutually advantageous, and in identifying the terms consistent with utilities' system requirements and management objectives.

Bilateral agreements are easier to negotiate and amend than multilateral agreements, however, all agreements must be filed with FERC and if FERC formally reviews an agreement, lengthy delays in implementing the agreement may occur.

The success of bilateral agreements in Florida is primarily a result of the cohesiveness and influence of the FCG organization. FCG member systems have established voluntary procedures that are closely followed by participating utilities and monitored by the FCG staff and committees.

The bilateral interconnection agreements have not inhibited utilities from reaching their current level of coordination. However, simple bilateral agreements may no longer be possible if FCG makes the transition to central dispatch. If FCG decides to establish systemwide central dispatch, it may require a comprehensive and potentially complex pooling agreement.

The only restraint to moving forward with more complete and sophisticated pooling in Florida is fiscal caution. Moving forward with complex, untried concepts requires assurance to any participant that it is a sound business step that will benefit (or at least cause no financial detriment to) its rate payers or investors. This assurance requires thorough study and evaluation before commitment to a pooling concept where the terms must be negotiated among a large number of parties with disparate sizes and varying goals. This approach is necessary but time consuming.

In addition to interconnection agreements between contiguous systems, transmission tariffs or agreements are required for economy interchange transactions between two systems when wheeling across a third system is necessary. Both tariffs and agreements have been used in Florida.

FPL and Florida Power Corporation (FPC) own most of the bulk power transmission facilities in Peninsular Florida. Each employs a slightly different contractual methodology to enable utilities not directly interconnected to use these facilities for enconomy interchange transactions.

FPC uses a tariff system in which transmission tariffs make a utility's transmission system available to all utilities for wheeling at a flat rate.

The wheeling charge incorporates average transmission losses and service charges regardless of the number of transmission-miles used.

FPL provides transmission service to requesting parties under transmission service agreements, which are applicable to the specific types of service provided for in the agreements or by the requesting party. The service agreements are specific about the points of delivery on the requesting party's system. The service charge is not based on specific lines or distances between the points of interconnection; transmission losses are applied based on the preceding year's average transmission losses.

FERC must examine and approve both types of arrangements. The conditions and rates for wheeling are negotiated by the utility owning the facilities and the parties desiring to use the facilities; FCG does not decide these rates.

Both bilateral transmission agreements and transmission tariffs allow widespread economic interchanges. However, the lack of a uniform transmission service rate in FCG may restrict economy interchanges as well as other types of interchanges between nonadjoining utilities. For example, because the energy wheeled across FPL and FPC transmission systems must be priced to recover both the negotiated FPL wheeling charge and FPC's flat wheeling rate, some interchange transactions involving wheeling may be restricted. If FCG members adopt a uniform transmission service rate, FPL and FPC will play a major role in establishing such a rate, because they own most of the transmission facilities in Florida.

According to the Florida Public Service Commission (FPSC) and some FCG member systems, the major cost savings from coordination result from centralized unit commitment and economy interchange. Moreover, these savings far outweigh the costs incurred through additional wheeling transactions. As a result, FCG has initiated an analysis of central dispatch, and plans to resolve wheeling rate issues as they arise.

Finally, significant capital expenses for new computer equipment will be required for coordinating energy dispatching requirements. Each member of a pool will probably be required to interface its existing computer equipment with that of all other pool members. Because of the cost and engineering complexity of converting each pool member to a common interface, it would probably be more economical to scrap individual computer systems and design and install a computer system specifically for the pool.

CHAPTER 4
REGULATORY BODIES AND POOLING

STATE COMMISSIONS

Each State in the Southeast Region has a regulatory commission.* All the commissions have authority over rates charged to customers by private electric utilities. Only three commissions, however, have authority to regulate rates outside the private sector:

- The Tennessee Valley Authority (TVA) supplies bulk power to municipal and cooperative utilities and fulfills a regulatory role in guiding the rate development of its distributors.
- The Virginia State Corporation Commission has full regulatory authority over the rates of electric cooperatives.
- The Florida Public Service Commission (FPSC) has jurisdiction over the structure of rates charged by cooperative utilities and publicly owned utilities.

No other commission in the region has jurisdiction over the rates of cooperative or publicly owned electric utilities. Because the regulatory authority of State commissions in the region is almost completely limited to jurisdiction over private electric utilities, the primary emphasis of the commissions' regulatory activities is statutorily thrust toward the interests of the electric consumers served by those utilities. However, in most States, consumers served by privately owned utilities represent a large majority of the citizens, and usually the public- or consumer-owned distribution utilities and their customers benefit from commission actions in a secondary way. The commissions are charged with ensuring that actions by utilities under their control do not result in rates to ratepayers in their jurisdiction that are higher than necessary for adequate and reliable service. No southeastern State except, possibly, Florida has a commission empowered to order coordinated action by all electric utilities serving the State.

Through their general powers, the commissions could effectively force certain power pooling arrangements. For example, the North Carolina Utilities Commission (NCUC) is required to forecast electric loads annually and develop a plan for meeting those needs. Certificates of Public Convenience and Necessity may be granted only if the generating unit in question is consistent with the plan. The plan, in turn, is required to consider power pooling. In

*In reference to electric utilities, the Tennessee Public Service Commission only regulates two small distribution utilities.

addition, the NCUC has "general supervision over the rates charged and service rendered." The NCUC can force pooling by refusing to grant Certificates of Public Convenience and Necessity and by adjusting the rate base and expenses in rate cases (and adjustment cases) as if pooling were occurring, but the commission probably cannot directly order power pooling. Most States must certify that the construction of generating plants meets the requirements of public convenience and necessity; in contrast, less than half of the State commissions in the Southeast Region have regulatory jurisdiction over the siting of transmission lines. Thus, in most States in the southeast, the State commissions generally have the ability (directly or indirectly) to minimize costs of generation and transmission through the pooling of production and transmission facilities of utilities under their jurisdictions.

In Florida, FPSC has been granted considerable authority to encourage increased coordination among the Florida utilities. FPSC's authority includes reviewing utilities' generating capacity expansion plans; requiring utilities to submit annually a 10-year plan for generating units and associated transmission lines they plan to build; and jurisdiction over planning, development and maintenance of a coordinated electric grid system throughout the State. FPSC has conducted studies with several Florida utilities regarding the feasibility of a statewide grid. The studies were inconclusive, but, substantial joint planning action among certain utilities was generated. FPSC has also enhanced the potential attractiveness of economy interchanges by specific rulings on the Florida Fuel Cost Recovery Clause. As a result of these actions by FPSC, there have been significant increases in the number of economic interchange transactions among the Florida utilities.

CONCERNS OF STATE COMMISSIONS RELATING TO POWER POOLING

Within the bounds of their responsibilities and authorities, State regulators have several concerns related to power transfers in addition to those discussed in Chapter 3.

The replacement of fuels used in energy transfers must be equitable. Pricing is not particularly difficult if the fuels used can be replaced immediately. However, if the fuels are taken under long-term contract and have the effect of shortening the contract by using the supply utility's fuels faster than intended, the task force agrees that the estimated discounted nominal cost of replacing that power in the <u>future</u> is the appropriate cost. Otherwise, the ratepayers of the originating company will pay higher electricity prices than necessary. On the other hand, excess charges must not be built into fuel prices, and the receiving ratepayers should gain an equitable share of the benefits. In energy shortages, ratepayers who have funded larger inventories over the years should not be disadvantaged by the transferring of their stocks to another utility to benefit coustomers who have not so paid.

Differing regulatory requirements can inhibit the successful pooling of generation and transmission. Issues of principal concern to a single State or small group of States might best be determined by a common board composed of representatives from the affected State commission(s) that can develop arrangements acceptable to themselves and consistent with their regulatory authority,

Federal involvement will not be necessary. The regulatory requirements of State commissions, together with those of FERC, must be closely coordinated. Joint FERC-State discussions and action might improve the resolutions of some issues.

STATE COMMISSION ACTIONS

The ratepayers served by State commissions can benefit by the study and approprite development of coordinated planning, construction, and operation of bulk power supply facilities. State commissions can aid the process through innovative ratemaking incentives that inherently recognize the benefits of pooling; generic cases to consider the impact of an efficient pooling system; and joint board activities with other States (and FERC).

ROLE OF THE FERC

FERC has the general responsibilities for regulating the interstate transmission and wholesale marketing of electric power. FERC's authority covers interstate rates and transfer of bulk energy of jurisdictional utilities under certain conditions, plus approval authority, but not enforcement, over rates charged for power from Federal projects. FERC can require physical interconnection of transmission systems if it can determine that the interconnection is in the public interest and will improve efficiency of use, conservation of energy, or reliability of service while not adversely affecting service or creating a burdensome economic loss for an affected utility.

ROLES OF OTHER FEDERAL AGENCIES

The Environmental Protection Agency establishes and enforces pollution abatement regulations with which the utilities must conform. The Nuclear Regulatory Commission regulates the construction and operation of all nuclear reactors and, in some cases, the transmission lines directly associated with the nuclear generating plants. The Economic Regulatory Administration (ERA) has the authority to promote and encourage voluntary interconnection and coordination of facilities among utilities, and to encourage voluntary industry activity and cooperation to ensure the reliability of the bulk power supply system. The Securities and Exchange Commission has jurisdiction over issuance of securities, consolidations among utilities, and accumulation of assets within utilities. The Rural Electrification Administration exercises financial control over rural electric cooperatives.

CHAPTER 5
VACAR (VIRGINIA-CAROLINAS) SUBREGION

AREA DESCRIPTION

The VACAR companies are composed of six utilities operating in Virginia, West Virgina, North Carolina, and South Carolina. The group is made up of the systems of Virginia Electric and Power Company (VIEP), Carolina Power and Light Company (CAPO), Duke Power Company (DUPC), South Carolina Electric and Gas Company (SOCG), South Carolina Public Service Authority (SOCA), and Yadkin Incorporated (YADI). (See Figure 5.)

VACAR has a generating capability of over 35,000 MW, of which coal-fired fossil steam represents 49 percent; nuclear, 21 percent; oil-fired fossil steam, 12 percent; hydroelectric, 7 percent; and combustion turbines, combined cycle, pumped storage, and one significant wind generator installation, the remainder.

The Virginia Electric and Power Company serves Virginia, West Virginia, and North Carolina. VIEP serves approximately two-thirds of Virginia; the remaining one-third is served by the Appalachian Power Company, a subsidiary of the American Electric Power Company, Inc.; in the southwestern corner, the Old Dominion Power Company, owned and operated by Kentucky Utilities Company; and in the northwestern corner, the Potomac Edison Company, a subsidiary of the (Allegheny Power Service Corporation). The small area served in West Virginia is in the southeastern section. The area served in North Carolina is in the northeastern corner and covers approximately 16 percent of the State.

The Carolina Power and Light Company serves the west-central and east-coastal sections of North Carolina, covering approximately 47 percent of the State; and serves the northeastern section of South Carolina and covering approximately 24 percent of that State.

The Duke Power Company serves the Piedmont sections of North Carolina and South Carolina. It serves approximately 28 percent of the area in North Carolina and approximately 26 percent of the area in South Carolina.

The South Carolina Electric and Gas Company serves the midlands and coastal sections of South Carolina and serves approximately 41 percent of the State.

The South Carolina Public Service Authority serves the coastal section of South Carolina only and serves approximately 9 percent of the area in the State

Yadkin, Inc. serves the Aluminum Company of America (ALCOA) and is located on the Yadkin River in the Piedmont section of North Carolina.

FIGURE 5--The Six Generating Utilities Comprising the VACAR Subregion

The VACAR bulk power transmission network at the end of 1978 with additions through 1988 is shown in Figure 6.

MEMBERSHIP AND ORGANIZATIONAL STRUCTURE

The VACAR membership is made up of five major utilities and one (Yadkin, Inc.) owned by ALCOA. (See Figure 7.)

The VACAR Executive Committee is composed of one senior officer from each utility. The executive committee has established task forces for the operating and planning functions for the VACAR group.

The VACAR Operating Task Force consists of one member from each of the utilities' operating departments. The duties of the VACAR Operating Task Force include, but are not limited to, the following.

- Maintaining appropriate daily communications
- Consolidating a 12-month VACAR generating maintenance schedule
- Reviewing and discussing summer and winter operating studies prepared by the operating task force
- Distributing the status of generating unit construction schedule twice annually
- Promoting economical interchange
- Formulating and exchanging reports to assess the impact of unusual conditions
- Periodically reviewing and discussing emergency assistance plans
- Implementing the VACAR security guide
- Periodically reviewing the adequacy of communication facilities
- Developing, administering, and updating interchange contracts
- Investigating solutions to special operating problems
- Policing spinning reserve policy
- Encouraging cooperation between control centers
- Developing united VACAR policy on operating matters
- Establishing a forum with production and environmental personnel
- Promoting the marketing of excess capacity and energy between companies
- Presenting to the Executive Committee problems that require their assistance

The Planning Task Force consists of one representative from each of the five major utilities. Members are appointed by the respective companies to serve indefinite terms. Duties include, but are not limited to, the following.

- Coordinating studies within VACAR
- Coordinating interregional studies
- Maintaining data on loads and facilities
- The Southeastern Electric Reliability Council (SERC) Coordinating Bulk Power Supply Program 1979-1998 for the Economic Regulatory Administration (ERA)--Preparing items for studies and future system plans, including maps. Currently this function involves preparation of items 5, 6, and 11 in the ERA FERC 383-3 filing.

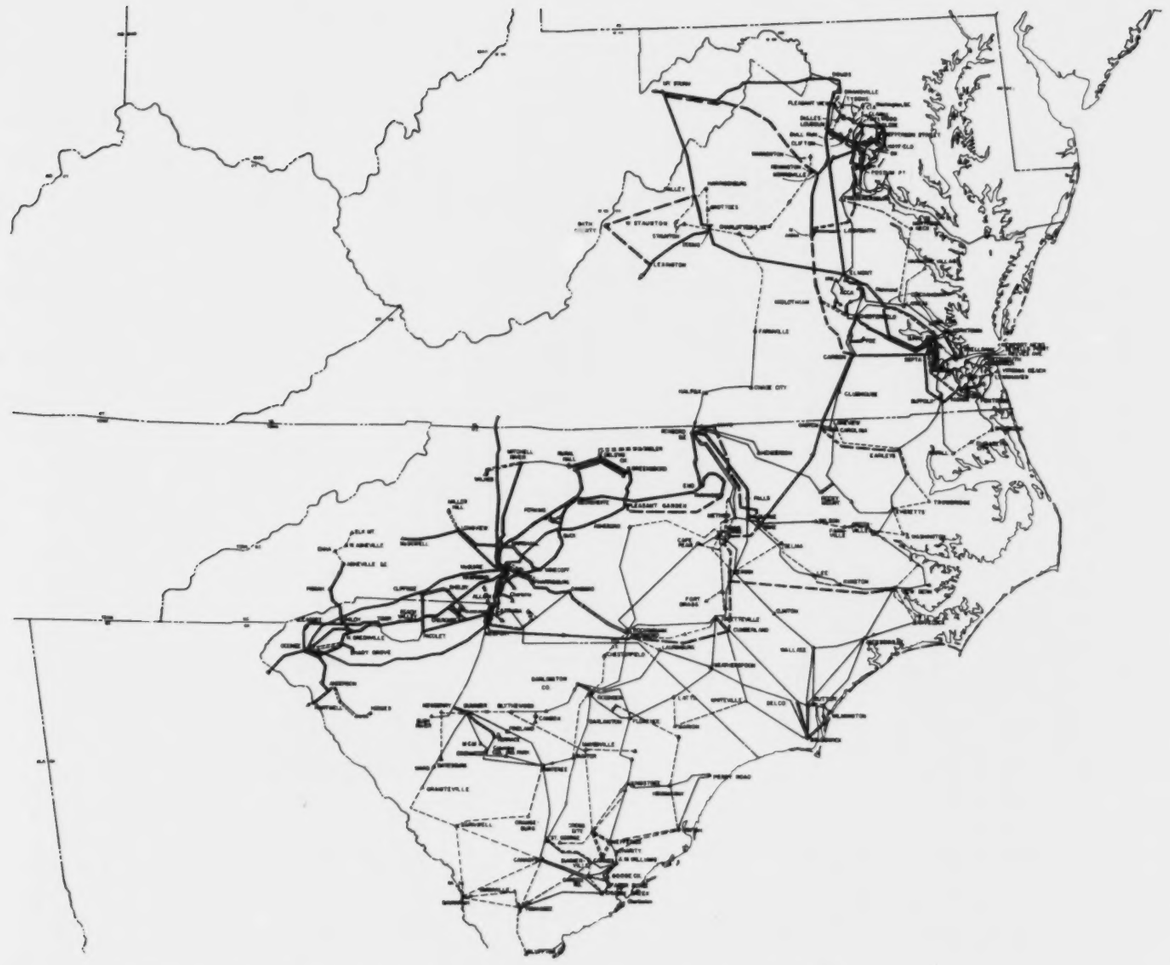

FIGURE 6--The VACAR Subregion Bulk Power Transmission Network

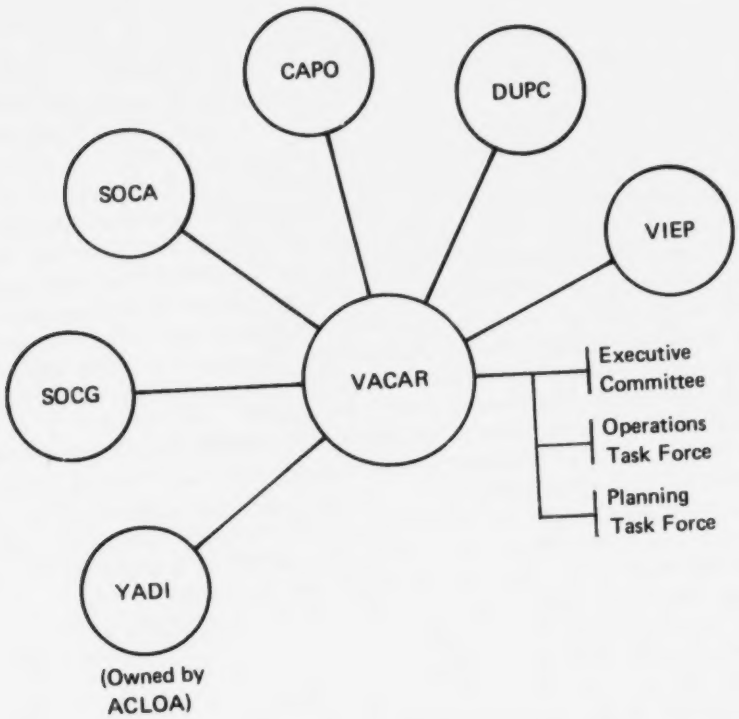

FIGURE 7--VACAR Membership and Organizational Structure

- Preparing a VACAR color map
- SERC and National Electric Reliability Council (NERC)--Coordinating requests as they relate to data required for studies
- Exchanging system data
- Discussing and evaluating new analytical methods and techniques

The Planning Task Force also provides the VACAR representatives to the following committees:

- The VACAR-Southern-Tennessee Valley Authority (VST) Steering Committee (one member)
- The VACAR-ECAR-MAAC (VEM) Study Committee (two members)

HISTORY OF ORGANIZATION

The VACAR companies have been operating as a reliability group since 1971. Before VACAR, four utilities in North Carolina, South Carolina, and Virginia formed an agreement known as CARVA (Carolinas-Virgina) to collaborate in the production and transmission of bulk electrical energy, with improved economy of operation and enhancement of reliability as major objectives. The four companies in CARVA were the Carolina Power and Light

Company, the Duke Power Company, the South Carolina Electric and Gas Company, and the Virginia Electric and Power Company.

AGREEMENTS AND CONTRACTS

Operating agreements developed by the VACAR group have proved to be effective instruments for economical and timely transactions of energy. These agreements and the resulting cooperation between the operating personnel of member companies have resulted in good operating performance.

During fuel shortages, energy has been transferred with "return-in-kind" transactions. During these periods, special provisions were made within the operating agreements to ensure the maximum transfer of energy, and fair compensation to the companies involved.

The Operating Task Force has developed and maintained workable agreements that permit the transfer of capacity and energy within the VACAR group under practically any operating conditions. These contracts provide for sharing of spinning reserves, assistance in emergency conditions, economy energy transactions, the sale of capacity for both short- and long-term periods, and coordinating maintenance schedules between member companies.

The spinning reserve agreement has significantly reduced the required reserve margins on each system and has generally increased the operating reserve level available to each company.

In the event of a loss of capacity in a member's system, these agreements provide for emergency assistance for 24 hours without a capacity charge. Assistance after 24 hours is provided with a minimum capacity charge. Spinning reserve agreements include two schedules for the sale of energy where capacity is not required. These two "energy only" schedules have provided the flexibility needed to facilitate energy transfers. Two schedules for supplying capacities are available depending on the firmness and length of time capacity required.

Provisions are included for the coordination of maintenance schedules. This coordination has assisted in the orderly maintenance of generating units while providing adequate reserves for all companies.

The Operating Task Force has established practices which assist in the maximum transfer of economy energy and resultant savings to all companies. Member companies place status reports on the VACAR teletype network by 9:00 a.m. and late evening each day. These reports include the necessary operating information to update all companies on the load-capacity status within the VACAR group, and information on the change in status of generating units. Procedures have been established for formal communications between interconnected control areas to determine the cost of economy energy on a current basis. Each control area logs the estimated cost of energy within the VACAR group and uses the information to help determine if there is a market for economy transactions.

COORDINATION OF PLANNING

The basic purpose of the Planning Task Force is to coordinate power supply and transmission planning. Studies are made continuously to assess

the adequacy of performance of the VACAR systems on a subregional basis, and to coordinate all evaluations made by VACAR and its member systems with those of other companies, subregions, or regions. The purpose of these studies is to provide planners with some of the information they need to develop individual system plans, and to prevent operation "surprises" that might occur through operation of the Southeast Region's strongly interconnected power systems. More emphasis is being placed on studying system capability to withstand severe disturbances during normal conditions, and when larger interregional transfers are in effect, without experiencing widespread cascading outages.

VACAR internal studies assess reliability and seek opportunities through coordination. The studies analyze the independently planned systems and determine whether weaknesses exist, so that the systems involved can take appropriate action. The effects of alternative or additional facilities are examined as needed to obtain optimum system performance. Annual studies are made representing 5- and 10-year projects. In most cases, 5 and 10 years of prior knowledge of potential problems will permit the implementation of transmission improvements through individual or combined system action.

VACAR also participates in reliability studies with its northern regional neighbors, the East Central Area Reliability Coordination Agreement (ECAR) and the Mid-Atlantic Area Council (MAAC), under the VACAR-ECAR-MAAC (VEM) Reliability Agreement. VEM is concerned primarily with the VACAR-MAAC, VACAR-ECAR, and ECAR-MAAC interfaces, all of which are located in the mid-Atlantic region. Two operating studies are made each year, one for the current summer and the other for the succeeding winter. One reliability or "future" study is made by VEM each year. The 5-year, future studies are made on odd-numbered years, and the 10-year studies are made on even-numbered years; thus, a 1982 study was completed in 1977 and a 1988 study in 1978.

The recently completed 1982 and 1988 studies showed that transmission systems of the three VEM regions can be expected to perform well on an interregional basis. Severe contingency testing demonstrated the ability of the interregional transmission systems to withstand severe stresses without experiencing widespread cascading outages.

The 1988 study included a limited review of the effects on interregional transfers that might be expected if certain critical generation and transmission facilities scheduled for completion during 1984-88 are delayed. The conclusions were that transmission delay would reduce transfer capabilities, and that the location of generation could have a significant effect on transfers.

VACAR also participates in reliability studies with Southern Company Services, Inc. and TVA through the Carolina Power and Light Company-TVA Agreement and the VACAR-Southern Reliability Agreement. The Florida Electric Power Coordinating Group (FCG) also participates in these studies.

The VACAR-Southern-TVA (VST) Steering Committee directs the activities of a working group that maintains a data bank from which all member companies can draw information for any studies needed, as well as for specific studies assigned by the Steering Committee. The VST Steering Committee consists of one member from the VACAR Planning Task Force (VPTF) and one representative each from the Southern, TVA, and Florida Subregions. The duties of the VACAR representative on this committee are as follows:

- o Representing the VACAR Planning Task Force (VPTF) at all VST Steering Committee meetings and keeping the task force informed of all matters of consequence
- o Sending copies of Steering Committee meeting minutes, study group instructions, and other documents of interest to VPTF members, the working group, and study group
- o Sending copies of all VEM reports to other Steering Committee members, including the Florida representative
- o Making the VACAR Subregion presentation at the annual meeting between the SERC-Technical Advisory Executive Committee and the planning engineers
- o Attending the joint meeting between NERC-IRS and SERC and assisting in the discussion as required
- o Assisting the chairman in preparing the SERC simulation studies index, which is usually updated in April and October of each year

Each year VST performs a 5-year study and a 10-year forecast. The capability of the subregions to transfer power under both normal and emergency conditions is analyzed thoroughly. When potential problem areas are recognized, the companies directly involved undertake joint two- or three-party studies to determine corrective action. An example is the recently completed Duke-Southern, SOCG and SOCA study of the Savannah River interface. The VST studies had shown that this interface would be a problem for subregional power transfers in the mid-1980's. The detailed study by the systems directly involved developed a satisfactory reinforcement plan.

Also, the Planning Task Force participates in operating studies with Southern Companies, the TVA, and the American Electric Power Company, Inc. These studies are made every 6 months to determine problems that may be encountered during the upcoming summer or winter peak periods. When problems are encountered, solutions are developed from the studies and appropriate recommendations are made.

Other duties of the Planning Task Force are:

- o Its Chairman attends all VACAR Executive Committee meetings and prepares a report for discussion.
- o A 5-year load, resource, and reserve table is prepared each January 1 for the Executive Committee and is mailed to members and alternates of all committees and task forces. This table is reissued during the year if significant changes occur.
- o One copy of all reports (VACAR, VAST*, VST, VEM) is sent to each VACAR Executive Committee and Operating Committee member and each committee's secretary for the VACAR permanent file.

The VACAR Planning Task Force makes a detailed report to the Executive Committee every 18 months in addition to brief reports to each meeting of the Executive Committee.

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*VAST is VST plus American Electric Power Company, Inc.

POSITIVE AND NEGATIVE RESULTS

The VACAR companies have operated efficiently, taking advantage of the economics associated with pool operation while maintaining the advantage of individual operation by each power system. The advantages of individual operation include close contact and accurate information exchange between the system dispatcher and plant operators, an understanding of an individual unit's effect on system security, and the increased cost control usually associated with decentralized operation. The value of interchange transactions to the member companies of the reliability group was estimated to be $9.1 million in 1978.

CARVA POOL AGREEMENT

The CARVA Pool Agreement provided that each company would continue to rely on its own judgment as to the best operating practices and requirements to serve the public within its own area, and the agreement was so constructed that all specific construction and operation plans, and rights and obligations of the member companies, were provided in appendixes. The appendixes, which formed the heart of the document, were (according to the terms of the agreement) to be formulated, amended, and supplemented by unanimous agreement of the Executive Committee. The Executive Committee was composed of one official from each of the member companies.

The basic tenets of the agreement were spelled out in Appendixes A, B, and C--the Pooling Plan, the Transmission Plan, and the Allocation Plan, respectively--which are summarized in the following sections.

APPENDIX A: THE POOLING PLAN

The concept employed in adding new generating unit additions is outlined in the following quotation:

> Each additional generating unit shall be, insofar as possible:
> (a) The largest size that the existing circumstances can justify.
> (b) Timed to meet the requirements of the combined loads, and
> (c) Scheduled, located and owned, in accordance with two factors:
> (i) The preferred location of the owning company to serve the prospective combined loads, either in an existing or a new site, and
> (ii) Staggering installations so that in the long run no one company will have an unreasonable capital investment made for the benefit of others, and no one company will be dependent on other companies for a disproportionate amount of capacity requirements.

Reserve requirements, as determined for the pool by the Executive Committee, were based on the principle of equalized reserves. Each company was responsible for the same percentage reserve, based on its own peak load, as that established for the pool as a whole. A company with less than the required percentage reserve bought the capacity necessary to meet its reserve obligation from member companies having capacity in excess of that required to meet the pool obligation.

The underlying principle of generating unit scheduling and reserve allocation was to protect the operating integrity of each system; that is, a company choosing to withdraw from the pool at some time in the future should not find itself unable to do so because of the lack of generating capacity. Generation within each system was dispatched in accordance with its procedures and needs, recognizing the energy associated with capacity sales and purchases.

APPENDIX B: THE TRANSMISSION PLAN

The Executive Committee had the responsibility of declaring specified transmission facilities as pool transmission facilities if, on recommendation of the Planning Committee, such facilities had been determined to serve the needs of the pool as a whole. The owner of a facility declared to be a pool transmission facility was reimbursed by the other companies for a fair proportion of the annual fixed capital charges, and operation and maintenance expenses of that facility, until the Executive Committee determined that the owning company would have required that facility or its equivalent for its own use.

The Planning Committee, which made the engineering studies, was a continuing committee composed of one representative appointed by each company. It was responsible for projecting pool resources and requirements for at least 5 years into the future, using data provided by the companies, and was charged to perform such other duties as directed by the Executive Committee.

APPENDIX C: THE ALLOCATION PLAN

On the basis of the reserve requirements established by the Executive Committee, each system was obligated to provide a percentage of reserve equal to that of the pool as a whole. However, provisions were made in the allocation plan to compensate for an inequitable allocation resulting from forecast error, allocating the minimum loading of generators during light load periods, or other reasons determined by the Executive Committee.

Pool transmission facilities were allocated on the basis of a common formula for calculating fixed charges that were to be applied to the capital cost of pool transmission facilities installed on a company's system.

The Executive Committee could authorize member companies to arrange with companies not members of CARVA for the sale or purchase of capacity. The expenses and benefits of such transactions were shared equitably among the member companies of CARVA.

PROBLEMS ENCOUNTERED

Operation of CARVA over time brought into focus significant differences among the pool member companies. For example, the relative sizes of the companies with respect to their peakloads and geographic areas created a problem from the outset. The peakloads of the companies were in the approximate ratio of 4:3:2:1. Duke Power Company was the largest and South Carolina Electric and Gas the smallest; VIEP and CAPO were in the ratio of 3:2. On the basis of the geographic area served by each of the companies, the load density of Duke was 133 kW per square mile and that of the other companies ranged between 42 and 55 kW per square mile. This difference in load density together with the nature of the load distribution within the service areas resulted in significantly different transmission configurations and design philosophies among the member companies.

Hydroelectric generation among the four companies had markedly different storage characteristics. Some hydroelectric facilities had essentially the same production capability each week; other hydroelectric facilities had seasonal storage capacity and were dispatched seasonally. The consequence was a difference in reserve criteria among the member companies.

One other problem that appeared early in the life of the pool was that nuclear generation, which had a high capital cost and low operating cost, was becoming economically attractive. The formula used to allocate the costs of participating generating units could not be applied equitably to nuclear generation, which had the effect of precluding nuclear units from consideration as pool participation units.

BASES FOR DISAGREEMENT

The CARVA agreement appendixes proved workable for everyday operations, but because of the differences among the member companies regarding reserve requirements and transmission concepts, the appendixes were unsatisfactory for pool use in these areas. The requirement of unanimous agreement of the Executive Committee was intended to accommodate different reserve and transmission philosophies, but in fact this principle proved unworkable and contributed to the demise of the pool.

The major areas of disagreement among the member companies were required generation levels, the designation of transmission facilities as "pool transmission facilities," and the pricing formula for generating capacity payments. Efforts to modify the CARVA Agreement continued for more than a year, but because of the widely divergent characteristics of the four systems, the differences were never resolved.

THE DISSOLUTION OF CARVA

After the Northeast blackout in November 1965, power systems became very conscious of service reliability. The member companies of CARVA felt obligated to pursue that objective even though attempts to modify the structure of CARVA had become deadlocked. On May 9, 1969, a proposal was

made that the necessary reliability studies be continued in a framework that was independent from the CARVA Agreement. This approach would divorce the area of reliability enhancement from the economic problems of the pool, and solutions to those problems could be pursued separately. The member companies recognized the need for a broader base for the reliability studies than was provided within the CARVA Agreement, and were aware that interchange agreements could probably be handled more expeditiously between individual parties than under the auspices of CARVA. It was also recognized that the pricing formula was excessively complicated and unwieldy, and that major difficulties still confronted the resolution of the nuclear capacity question.

Consequently, on April 30, 1970, an agreement was signed which terminated the CARVA pool, although certain commitments for capacity and transmission were to be kept as stipulated in the terms of the CARVA Agreement until they expired. The termination agreement noted that all the parties had become members of the Southeastern Electric Reliability Council (SERC) and that the goals for reliability could be pursued more objectively through the auspices of the Virginia-Carolinas Subregion of SERC than had been possible in CARVA.

CONCLUSIONS

Although hindsight is generally very good and foresight frequently myopic, several principles have come into focus with the CARVA experience which are inherent in the pooling concept, and not necessarily a result of lack of foresight on the part of the organizers of the CARVA Pool:

1. Where the partners in a pool are of significantly different size, the smallest tends to gain the most, and the largest to gain the least.
2. The degree of pooling desirable is an inverse function of the right to retain corporate autonomy among each of the participating companies in a pool. The management of a pool is inherently authoritarian, and will pre-empt the management of the member companies, not necessarily to the benefit of all the member companies. The total benefits derived from pooling must be weighed against the costs to achieve those benefits.
3. Power pooling is not essential to the achievement of system reliability and in some cases can be a deterrent to that objective.

EVALUATION BY VACAR COORDINATING GROUP OF ITS CURRENT STATUS

The VACAR Coordinating Group concludes that additional savings associated with a formal power pool of the VACAR companies would be minimal and that current operating agreements, communications facilities, and operating procedures ensure minimal use of petroleum.

The VACAR Operating Committee has a continuing responsibility to ensure the efficient consolidated operation within its reliability and interchange agreements. Recently, various operating procedures and interchange agreement changes have resulted in improved operations. This committee expects to continue to promote efficient and reliable operation of the VACAR companies.

CHAPTER 6
SOUTHERN SUBREGION

SOUTHERN SUBREGION AREA

The Southern Subregion of the Southeastern Electric Reliability Council (SERC) includes the operating companies of the Southern electric system (Southern Company) together with other SERC members in Alabama, Georgia, Mississippi, and the panhandle of Florida: Alabama Electric Cooperative, Inc., Crisp County Power Commission, Savannah Electric and Power Company, Southeastern Power Administration (SEPA), and South Mississippi Electric Power Association. This area also includes the Municipal Electric Authority of Georgia (MEAG), the Oglethorpe Power Corporation (OPC), and the City of Dalton, all of which are in Georgia.

The Southern Subregion is shown in Figure 8, and its bulk power transmission network is shown in Figure 9.

SOUTHERN ELECTRIC SYSTEM

AREA DESCRIPTION

The Southern electric system includes the Alabama Power Company, the Georgia Power Company, the Gulf Power Company, and the Mississippi Power Company. The four systems include an area of 122,000 square miles that covers most of Alabama and Georgia and smaller sections of Mississippi and Florida. The Alabama Power Company serves more than three-fourths of the area of Alabama; the Tennessee Valley Authority (TVA) serves the northern portion. The Georgia Power Company system covers almost all of Georgia; small sections of the State are served by the TVA in the north and the Savannah Electric and Power Company in the southeast. The Mississippi Power Company service area covers most of the southeastern quarter of Mississippi, and the Gulf Power Company system, located in the western end of the Florida Panhandle, covers about half of the panhandle area. The bulk power transmission network of the Southern electric system is shown in Figure 10.

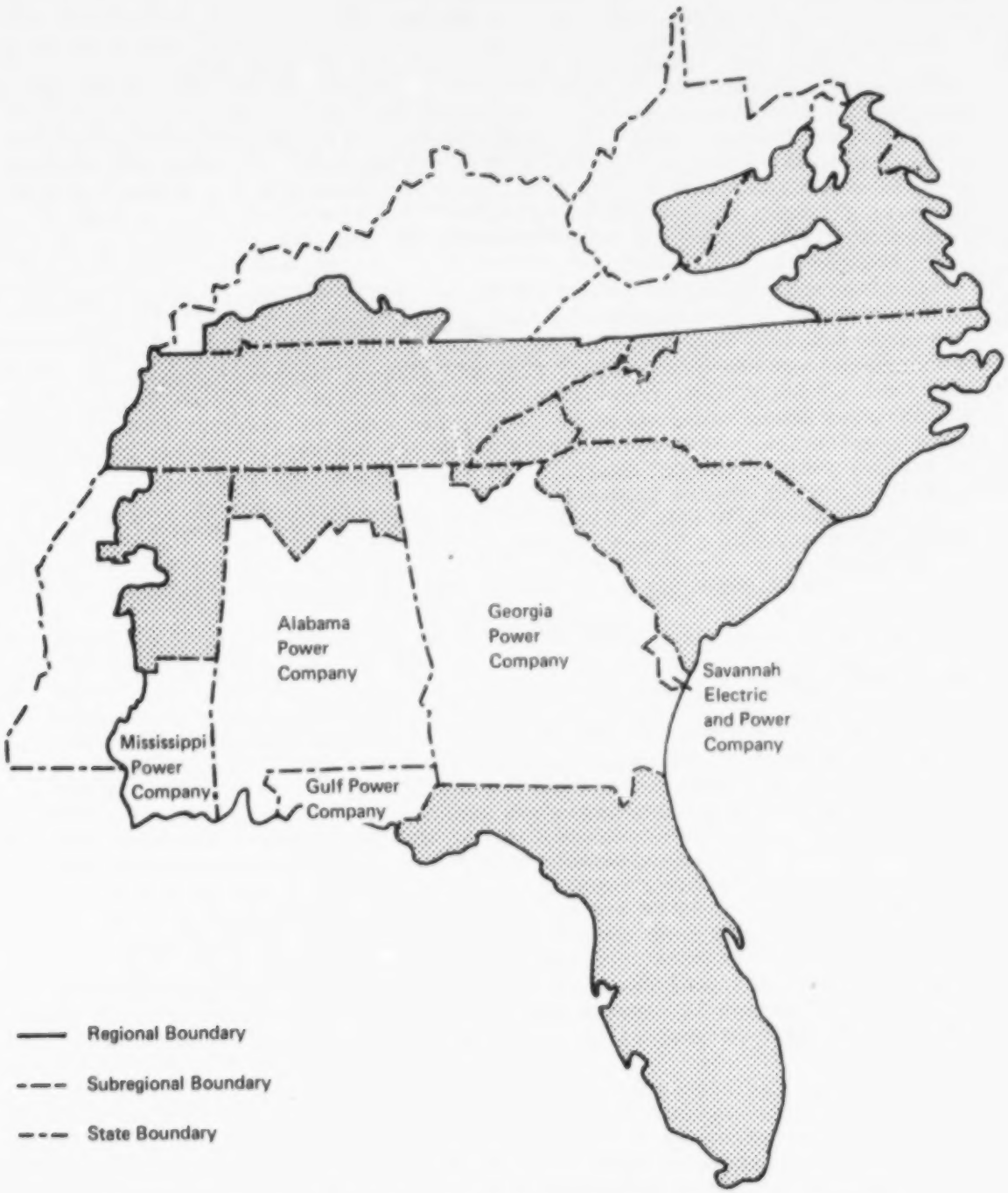
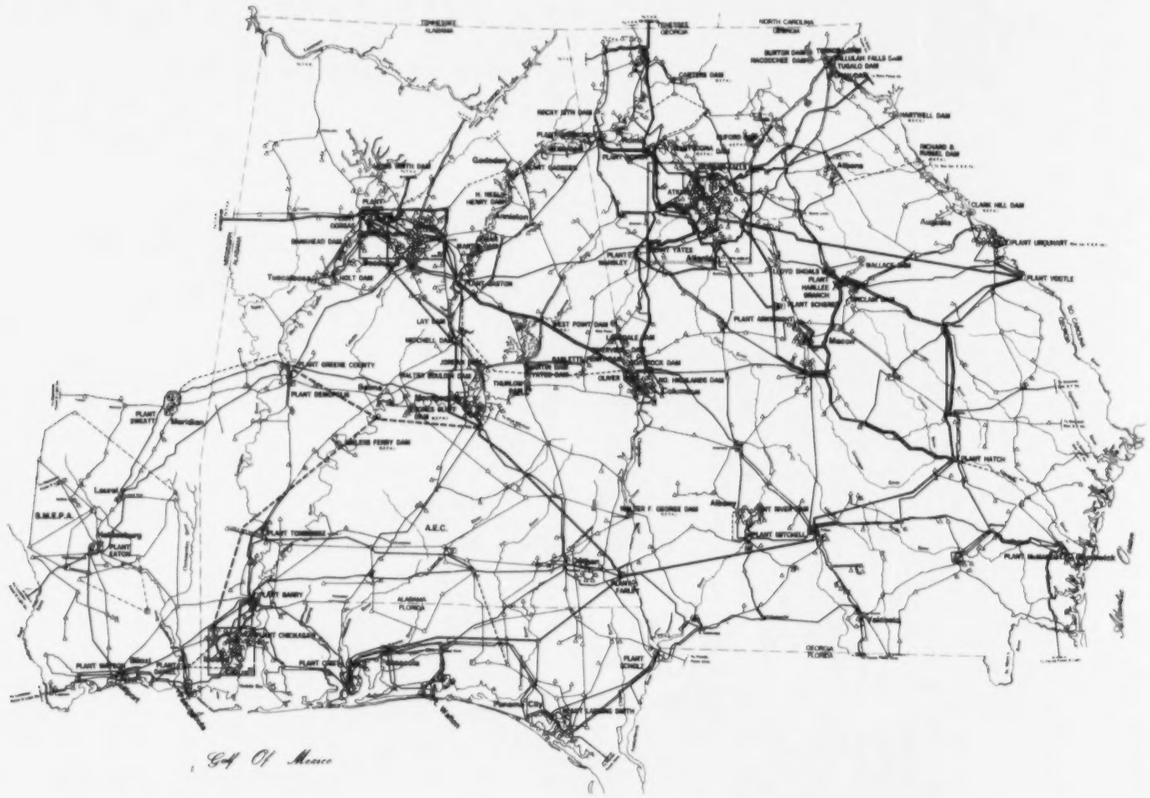


FIGURE 8--The Investor-Owned Utilities in the Southern Subregion


TENNESSEE
ALABAMA
GEORGIA
NORTH CAROLINA
GEORGIA
BURTON DAM
NACOOCHEE DAMS
TERRORA
TALLULAH FALLS DAM
TUGALO DAM
HARTWELL DAM
RICHARD B.
RUSSELL DAM
CLARK HILL DAM
PLANT URQUHART
PLANT VOGTLE
WALLACE DAM
LLOYD SHOALS
PLANT
HAMMOND
BRANCH
PLANT SCHERER
PLANT MCMANUS
PLANT GRIFFITH
PLANT
WANSLEY
ATLANTA
ATHENS
ROME
GADSDEN
GUNTERSVILLE DAM
WHEELER DAM
WILSON DAM
WILSON
MUSCLE SHOALS
WIDOWS CREEK
PLANT
COLBERT
PLANT
GALLATIN
PLANT
JOHNSONVILLE
PLANT
KINGSTON
KINGSTON
CHATTANOOGA
NICKAJACK DAM
GUNTERSVILLE
HIWASSEE DAM
APALACHIA DAM
BLUE RIDGE DAM
OCOEE NO. 3
OCOEE NO. 2
OCOEE NO. 1
OCOEE NO. 2
OCOEE NO. 3
OCOEE NO. 1
BLUE RIDGE
APALACHIA
HIWASSEE
CHICKAMAUGA DAM
HALES BAR DAM
WATTS BAR DAM
CHICKAMAUGA
WATTS BAR
SEQUOYAH
SEQUOYAH
SOUTH
PITTSBURG
PLANT
WIDOWS CREEK
PLANT
SHAWNEE
PADUCAH
KENTUCKY DAM
KENTUCKY
PLANT
PARADISE
PLANT
GREEN
RIVER
PLANT
CANE RUN
PLANT
MILL CREEK
PLANT
TRIMBLE
COUNTY
PLANT
CLIFTY
CREEK
PLANT
GHENT
PLANT
KYGER
CREEK
PLANT
CARDINAL
PLANT
BIG SANDY
PLANT
KANAWHA
RIVER
PLANT
JOHN E.
AMOS
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MOUNTAINEER
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MITCHELL
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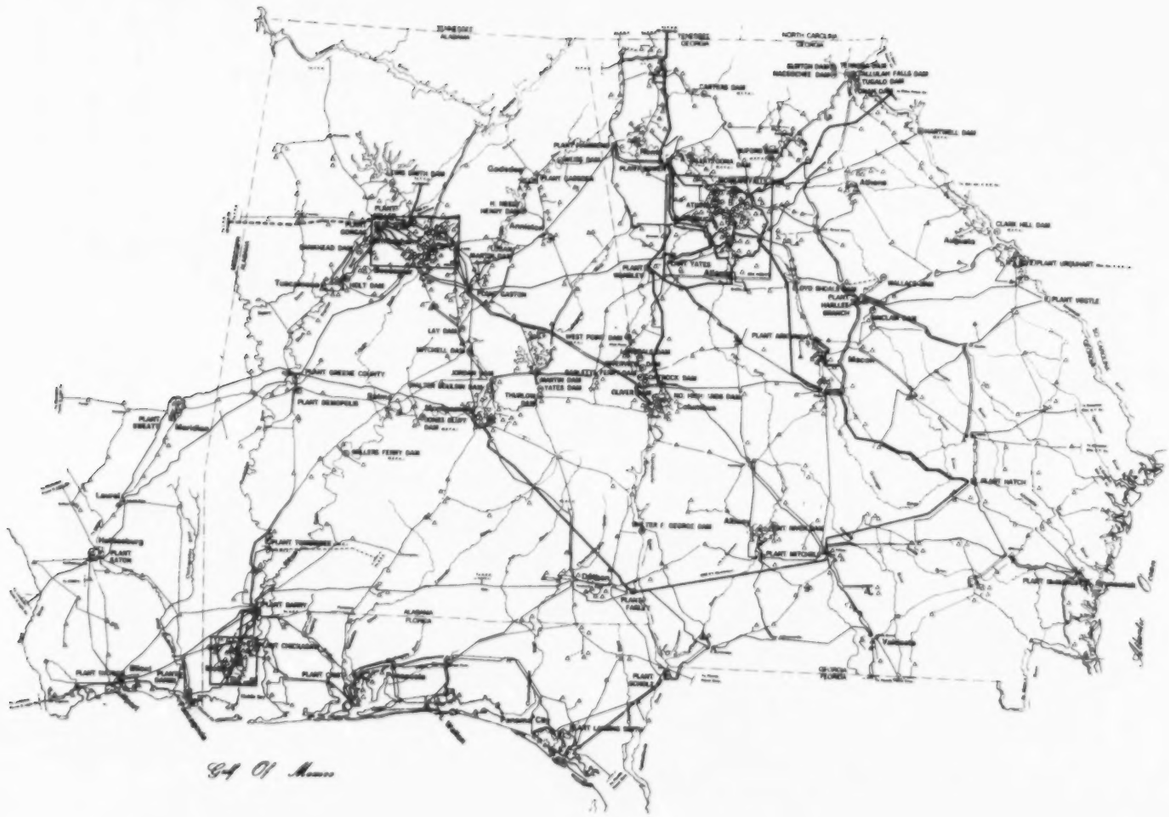

FIGURE 10--The Southern Electric System Bulk Power Transmission Network

AREA CHARACTERISTICS INFLUENCING COORDINATION

Pooling and coordination among the several operating companies of the Southern electric system have been encouraged and facilitated by the holding company concept. Under the umbrella of a common source of equity capital, these operating companies have been able to accommodate one another, to trust the judgment and competency of their managements, and to increase their opportunities to cooperate and support one another. These accomplishments have been aided substantially by the use of a common service company in coordinating the planning, construction, and operation of the respective electric systems. As a result, the coordination has reached a level of sophistication that captures many of the possible benefits of power pooling. Sophisticated coordination does exist among certain public and investor-owned utilities. The arrangements between the operating companies of the Southern electric system and the TVA provide a high degree of coordination that is extremely beneficial from an economic, as well as a reliability, standpoint. Likewise, coordination has been effected with generating cooperative and municipal entities since their inception. The degree of coordination has varied according to the circumstance and the perceived impact that such coordination would have on the cost of providing service to the customers of the system involved.

Legislation has been enacted in the State of Georgia to enable municipal systems to participate in joint actions. Accordingly, MEAG was established to facilitate the development of a dependable source of electric power for the political subdivisions of the State.

Power pooling is being discussed by MEAG, the Georgia Power Company, the Oglethorpe Power Corporation, and the City of Dalton. Some discussion has addressed the possibility of a Georgia Power Pool being structured in a manner that would allow the Savannah Electric and Power Company to be a member.

Coordination between the Alabama Power Company (APC) and the Alabama Electric Cooperative (AEC) has evolved to encompass interconnection agreements involving joint use of transmission facilities, reserve requirements, the purchase and sale of electric capacity, and energy for long-term needs as well as for emergency and maintenance purposes. Negotiations concerning the provision of transmission services or wheeling are underway . Negotiations are also taking place between AEC and the Gulf Power Company in Florida for possible interconnection and service arrangements with respect to AEC's supply to four distribution cooperatives in northern Florida.

However, there has not been complete accord in arriving at mutually agreeable contract terms for achieving such goals. Often, parties disagree as to the burdens that should be assumed by one party to confer a benefit on the other. Mutually agreeable terms and conditions for interconnected operations between APC and AEC have been difficult to determine. Requests have been made for terms and conditions that would impose burdens on Alabama Power's provision of service to its customers and resistance to such requests has been viewed by Alabama Electric as an inappropriate restraint on its

ability to provide power by construction of small, relatively inefficient generating plants.*

Moreover, negotiations in 1970-72, conducted under the leadership of the Federal Power Commission (FPC) staff and directed toward increased interconnection and coordination between Alabama Power and Alabama Electric, became encumbered with extraneous matters. Those discussions, which basically focused on improvements in reliability needed for Alabama Electric's system as a result of its construction of a small generator remote from its load center, suffered long delays because Alabama Electric insisted that the proposed interconnection agreement provide for exclusive retail service areas for its member cooperatives. When such matters were eliminated from the negotiations, a comprehensive coordination arrangement was consummated that provided beneficial terms to Alabama Electric to enable it to achieve significant economies and reliability.

Until recently, the arrangements between Alabama Power and Alabama Electric centered around the basic need by Alabama Electric for a firm bulk power supply to serve its loads. As a result of Alabama Power's provision of a supply of the firm power needs of Alabama Electric in excess of its own generating resources, Alabama Electric has grown much more rapidly than neighboring utilities. From 1945 (when it took over the existing system of Alabama Water Service Company) through 1976, it had a 2300-percent increase in energy sales, a growth record unparalleled in the Southeast. After completing its second unit at the Tombigbee Steam Plant, it no longer needed a firm power supply from Alabama Power, and contractual negotiations were begun to change their relations. In the opinion of Alabama Power, these negotiations probably can be concluded to the mutual satisfaction of both parties.

One area of potential increase in coordination benefits is the increased use of coal to displace oil-fired capability in other areas. To attain such benefits in a timely manner, the stringent air and water pollution requirements should be relaxed. Under current regulations, emissions must not only be reduced to avoid harm to persons and property, they must be reduced to avoid degrading the air itself. Such regulatory overkill not only adds unwise cost burdens that make construction of coal-fired generation difficult, it also adds immeasurably to the problems of plant operation and maintenance.

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*AEC contends that APC's characterization of its refusals to coordinate may be contrasted to the findings of the Nuclear Regulatory Commission's antitrust review of APC's conduct. See ID. (I) 5 NRC 804, at 925 (1977), wherein the NRC Licensing Board finds that Applicant "Consistently refused to make fair interconnection and coordination arrangements with AEC, for the sole purpose of maintaining and protecting Applicant's wholesale customer business from competition by AEC. Applicant's refusals to offer AEC reasonable interconnection and coordination in these circumstances can only be viewed as anti-competitive, and inconsistent with the antitrust laws and their underlying policies. We find that Applicant's behavior in regard to offering AEC interconnection and coordination in this period evinces an anti-competitive intent toward AEC."

POWER POOL MEMBERSHIP AND ORGANIZATIONAL STRUCTURE

The Southern Company* is a registered public utility holding company under the Public Utility Holding Company Act of 1935. Its structure and operations are regulated by the SEC under the terms of the Act.

The Southern Company owns all the outstanding common stock of its four operating subsidiaries (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company) and that of a wholly owned service organization, Southern Company Services, Inc. The chief executive officer of each of the subsidiary companies is a member of the board of directors of the Southern Company, which also consists of 12 outside directors who reside in the service territory of the operating subsidiaries. The membership and organization of the Southern Company are shown in Figure 11.

The operating subsidiaries of the Southern Company are physically interconnected at multiple points and, through the coordination services provided by Southern Company Services, Inc., operate as a single integrated electric system, thus providing mutual support for the respective operating companies, achieving substantial economies, and conserving resources.

HISTORY OF POWER POOL ORGANIZATION

The evolution of the Southern Company can be traced to the turn of the century, when the electric utility industry was in its infancy.

In 1912, Alabama Traction, Light and Power Company, Ltd. acquired the common stock of several isolated and independent electric companies in Alabama. This holding company was organized under a Canadian charter to attract capital from English investors. Their capital investments were essential because efforts to secure capital funds in the United States had failed. Alabama Traction became the first public utility holding company in the South. Its major subsidiary was Alabama Power Company. The earliest known predecessor of Georgia Power Company was Georgia Railway, Light and Power Company, which was started around 1892. In 1920, the Alabama and Georgia systems were interconnected, so that the transmission network encompassed seven major electric systems in five southeastern States. This interconnection marked the beginning of what ultimately evolved into the Southern Company.

In 1924, Southeastern Power and Light Company displaced Alabama Traction, Light and Power Company, and in 1926 it acquired the Georgia Railway and Electric Power Company. Electric utility properties were also acquired in Florida, Mississippi, South Carolina, and Tennessee during the 1920's.

The Commonwealth and Southern Corporation, a Delaware corporation (C & S Delaware) was formed as a holding company in 1930 through the merging of Southeastern Power and Light Company and its subsidiaries with Commonwealth Power and its northern subsidiaries. This merger made an 11-company

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*The term "Southern electric system" used herein refers to the combined system of the operating companies of the Southern Company.

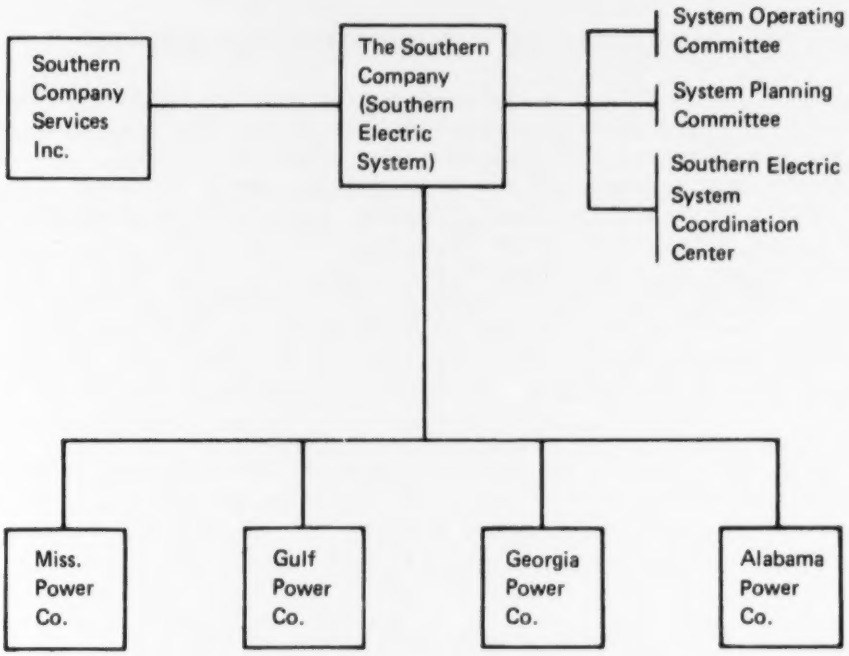

FIGURE 11--Membership and Organization of the Southern Company

corporation with operations in Alabama, Georgia, Florida, Mississippi, South Carolina, Tennessee, Pennsylvania, Ohio, Indiana, Illinois, and Michigan.

After the crash of the stock market in 1929 and the depression that followed, public pressure existed for the Federal Government to provide jobs through the construction of public works. In 1933, Congress passed the Tennessee Valley Authority Act. Subsequently, C & S Delaware sold its Tennessee properties (Tennessee Electric Power Company) to TVA, which was created to develop the Tennessee River but which was soon to emerge as a large, integrated electric system serving several States.

As a result of the administration of the Public Utility Holding Company Act of 1935, which prohibited holding companies from owning companies that were not geographically connected, C & S Delaware was directed by the Securities and Exchange Commission (SEC) to be dissolved. However, as a step in the dissolution, the SEC in August 1947 approved the Southern Company's acquisition of the companies owning the southern properties of C & S Delaware that were engaged in the supply of electric power, except for South Carolina Power Company. That company was sold to South Carolina Electric and Gas Company in 1947. Thus, the Southern Company was left with its present subsidiaries: Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company. Each company is a separate corporation, the common stock of which is owned by the Southern Company. The SEC found in its

August 1947 order that the common ownership of these four companies by the Southern Company met the physical integration and coordination standards specified in the Public Utility Holding Company Act of 1935.

The evolutionary growth and development of Southern Company Services, Inc., (SCS) parallels that of the Southern Company. SCS provides the companies in the Southern Company with engineering, purchasing, marketing, financial, data processing, systemwide power dispatching, and other specialized services. SCS is an organization of specialists whose widely varied talents, professional abilities, skills, and knowledge are centralized for the benefit of the entire system. SCS is a nonprofit organization, providing services at cost and recovering these costs each month from the other system companies. It maintains offices in Birmingham, Atlanta, and New York City.

SCS can be traced to 1917, when the Dixie Construction Company (a subsidiary of Alabama Power Company) was created to provide it with engineering and construction services. Dixie was purchased in 1925 by the Southeastern Power and Light Company, which also organized the Empire Construction Company to do engineering work for Georgia Power Company. In addition to the engineering and construction services provided by Dixie and Empire, the Southeastern Power and Light systems were served by Southeastern Engineering Company (management services) and Southeastern Securities Company (financial services).

After C & S Delaware (the holding company) was formed, a New York corporation, the Commonwealth and Southern Corporation, (C & S New York), was organized to provide utility services; all of Southeastern's service companies were dissolved thereafter. The assets of Dixie and Empire were acquired by Allied Engineers, Inc., the service organization in the Commonwealth Power System. In 1931, Allied Engineers was dissolved.

C & S New York in New York handled all financial, statistical, corporate, tax, and certain other work now performed by SCS; however, most power pool, engineering, and rate matters for the southern group of operating companies were handled by C & S New York in Birmingham. Similar phases of work were handled for the northern group in Jackson, Michigan.

With the dissolution of C & S Delaware and its termination as a holding company, SCS was organized as an Alabama corporation, the stock of which was originally owned by the four operating companies of the Southern Company. SCS was approved by SEC as a mutual service company under the terms of the Public Utility Holding Company Act and on November 1, 1949, began to perform the functions that C & S New York had performed for the Southern electric system. SCS maintains headquarters in Birmingham, Alabama.

In 1963, the Southern Company acquired all the outstanding capital stock of SCS, and SCS became a direct subsidiary of the Southern Company. The officers and employees of the Southern Company who were experienced in electric utility operations and planning became officers or employees of SCS. The principal objectives of this reorganization were to strengthen the effectiveness of systemwide planning and coordination, to allocate more equitably all costs of management functions performed by holding company personnel among the system companies, and to eliminate duplication of activities and use system personnel more effectively.

POWER POOL AGREEMENTS AND CONTRACTS

INTERCOMPANY INTERCHANGE CONTRACT

An Intercompany Interchange Contract (IIC), of which all the companies are signatories, has been in effect since about 1935, but the basic principles of fully integrated and coordinated operation were embodied in a contract for 1940 signed in 1939. The contract has been modified to take into account changing system conditions, but the basic principles embodied therein have not changed substantially.

Various provisions of the IIC cover such matters as allocation of reserve requirements, capacity credits, determination of capacity purchases and sales among the operating companies, rates applicable to capacity and energy purchases and sales, provisions for automatic generation control and systemwide power system coordination, and accounting and billing procedures.

The IIC is reviewed and updated annually to account for changing capacities, rates, and other conditions.

The IIC provides for establishment of the System Operating Committee, which is composed of an operating representative of each operating company and SCS at an officer level or equivalent. The representative of SCS serves as chairman but has no voting privilege. All decisions of the Operating Committee must be unanimous to become effective.

Among the duties of the System Operating Committee are developing concepts, determinations, and conditions of the IIC; providing guidance and direction to SCS for coordination of economic power system operations; establishing guidelines and procedures for power system reliability; establishing provisions to be included in interconnection agreements between the four operating companies and neighboring utilities; and providing other general direction associated with the Southern Electric System Coordination Center and Power Management System, the telecommunications network, and other similar power system facilities that relate to the overall coordinated operation of the Southern Company.

INTERCHANGE BILLING

Although moment-to-moment dispatch is on an economic basis, billing is accomplished after the fact on an hourly basis. Transactions are assumed to be between each operating company and the pool, and energy exchanges are priced on the basis of rates established under the provisions of the IIC. Rates are updated monthly to reflect actual energy costs of the various units on the system. Each company retains its lower-cost energy resources for its customers and sells any remaining higher cost resources to the pool. Capacity purchases and sales are based on installed capacities and actual loads occurring each month, and rates applicable thereto are those developed in the IIC.

Although billing is accounted for and accomplished hourly, bills are rendered on a monthly basis to each operating company.

INTERCONNECTION AND RELIABILITY AGREEMENTS

In addition to the IIC, the four operating companies have interconnection agreements with the following nonassociated utilities: Duke Power Company, Florida Power Corporation (FPC), Mississippi Power and Light Company (acting as an agent for the Middle South Utilities System), South Carolina Electric and Gas Company, and TVA. A new interconnection with Florida Power & Light went into service in late 1979, and interconnection agreements are being negotiated with Florida Power & Light and the Jacksonville Electric Authority. In addition, the companies have bilateral agreements with the following:

- Alabama Power Company/Alabama Electric Cooperative
- Georgia Power Company/Savannah Electric and Gas Company
- Mississippi Power Company/South Mississippi Electric Power Association
- Georgia Power Company/Municipal Electric Authority of Georgia
- Georgia Power Company/Oglethorpe Power Corporation
- Georgia Power Company/City of Dalton
- Georgia Power Company/Crisp County
- All companies individually with the Southeastern Power Administration

Moreover, the operation utilities in the Southern Company have separate reliability agreements with the companies comprising Virginia-Carolinas (VACAR), TVA, Middle South Utilities, and the Florida Coordinating Group (FCG) (now under negotiation).

RESPONSIBILITIES OF POOL MEMBERSHIP

COORDINATION OF PLANNING

Generation is planned and installed by each operating company to serve its customer load requirements over time. In any year, one or more of the operating companies may have either more or less installed generating capacity than it requires. Operating companies engage in purchases and sales of power among themselves to cover temporary shortages and to dispose of temporary excesses of power supply. The following is a brief summary of the steps involved:

- Load estimates are prepared by each company by using the latest techniques available. Similarly, load estimates are made by SCS and the results are compared. Each operating company then makes a final determination of its projected load requirements. Diversities are applied to the companies' load projections on the basis of historical data, and total Southern Company system load requirements are projected.
- SCS assists the operating companies in establishing plans to include the type and size of generation that will satisfy their projected load requirements. These plans are reviewed by the System Planning Committee, which comprises representatives from each of the operating companies and

SCS. Alternatives are developed from which a system generation expansion plan is derived. Contingency plans then are often developed to meet possible future changes in the system. When the system generation expansion plan is agreed on, the System Planning Committee makes its recommendation to the operating companies through the System Operating committee, which also has one representative from each of the operating companies and SCS. After review by the System Operating Committee, assuming that other alternatives are not suggested, the system expansion plan is submitted to the management of each of the operating companies for approval of the capital additions the companies will need to construct or install to implement the system plan.

- The recommendation of the System Operating Committee, if adopted, amounts to approval of the inclusion of plant capacity additions for credit in the IIC when such capacity goes into service.
- Tentative transmission expansion plans are developed along with the generation expansion plan to ensure that overall economic evaluations include the impact of transmission.
- Although many considerations go into developing generation expansion plans, some of the more important ones are the location of projected loads; the need for base, intermediate, and peaking generation; type and location of plants based on fuel availability; environmental requirements; transmission requirements; and firm purchase or sale obligations with other utilities.
- In developing the generation expansion plans, economic evaluations are made to compare the alternatives in order to minimize revenue requirements associated with the ultimate plan selected.
- For any generation expansion plan that may be implemented, any operating company may have temporary surpluses or deficits from year to year. These deficits are sold to, or purchased from, other system companies under provisions of the IIC (see following Coordination of Operations paragraphs).

SHARING OF COSTS

Certain costs are shared under procedures designated as part of the IIC. Adoption of the coordinated expansion plan by the System Operating Committee and management approval of the separate operating companies amounts to approval for the inclusion of the facility additions for credit in the IIC. Facilities included then become the basis for determining charges between the operating companies, in accordance with methods approved by the operating companies and prescribed in the IIC. These procedures define requirements for the following:

- Territorial loads, hydroelectric and fuel generation, energy received and delivered to other companies, and energy losses
- Accounting periods
- Determinations of rates for energy purchased from, and sold to, the pool, and pool energy rates

- Classification of interchange energy and determination of charges for interchange energy purchased from and sold to the pool
- Development of monthly load ratios and peak period rates
- Monthly capacity requirement determinations
- Monthly capacity payments
- Determination of capacity resources and capacity evaluation
- Classifying seasons
- Generating unit delay adjustments
- Month-end adjustments of daily energy determinations
- Tieline frequency regulation by hydroelectric capacity
- Purchase and sale of energy with nonassociated utilities
- Allocation of pool energy
- Seasonal power exchange
- Charges for transmission facilities
- Monthly billing

COORDINATION OF OPERATIONS

The operating companies of the Southern Company have operated on a coordinated basis for almost 50 years; fully integrated operation has been employed for more than 40 years. The operating companies have always been held together through the bonds of the holding company device with its common source of equity capital. Moreover, fully integrated and coordinated operation has been an accepted philosophy of operation and was realized in 1939 when the contract for 1940 was accepted by the companies. Systemwide capacity control was originally provided by hydroelectric regulation, and thermal units were incrementally loaded in steps, based on precalculated heat rates and fuel prices.

In 1954, systemwide dispatch was transferred to SCS by the establishment of a Power Coordination Center in Birmingham, Alabama, which employed the world's first computer used to determine the incremental cost of power delivered to load centers. This computer, the "Early Bird" (named for Don Early, who pioneered in this field), provided for a determination of incremental generating costs and incremental transmission losses to minimize total production costs and optimize efficiency. For many years, the loading of steam units continued to be on a manual order basis with system control (regulation) accomplished on hydroelectric units. In 1958, automatic generation control was installed on the steam units throughout the Southern electric system for use on a continuous economic dispatch basis, the hydroelectric control being retained for backup.

Because of the needs for state-of-the-art advances in supervisory control, expansion of computer facilities for automatic generation control, and better means to assess system security, a modern state-of-the-art coordination center was built to replace the old facility. This center, the Southern Electric System Coordination Center, which went into operation in 1973, and provides for systemwide economic dispatch, supervisory control, and system security analyses. Dispatch of the generating units is accomplished by sending electronic control signals directly to the units of the operating

companies. As a routine matter, units are loaded or unloaded in accordance with the impulses from the coordination center; however, the final decision relating to the operation of the generating units rests with the individual operating company.

POSITIVE AND NEGATIVE RESULTS OF POOLING ORGANIZATIONS

As a result of their coordinated planning and operation, the operating companies of the Southern Company have effectively used the prevailing time and character of load diversities, the diversities in stream flows, and economies of scale in production from adding larger and newer concepts in generation. Moreover, the interconnected and integrated planning and operation have enabled these companies to maintain a higher level of reliability with a relatively lower margin of installed reserves.

The Southern electric system has also benefited by financing through the holding company structure and by sharing technological advances in planning operation and equipment. These benefits and coordinated transmission planning have enabled the maintenance of acceptable system reliability with reduced reserve generation and lower operating costs.

The following calculations illustrate the benefits possible through several of the coordinating vehicles discussed.

SEASONAL EXCHANGE

The Southern electric system has a seasonal exchange contract with TVA that provides 300 MW of firm capacity during the Southern electric system's peak period. Similar contracts with other nonassociated companies were maintained in previous years, and there may be similar contracts in the future.

Because this capacity is not available throughout the year and yearly production costs are increased somewhat by is unavailability, a high penalty (50 percent) is applied to the annual benefits available from seasonal capacity. The following estimated benefits are based on replacement at approximately the embedded cost of capacity for the Southern electric system ($55.00 per kilowatt-year).

$$\text{Estimated Annual Benefits} = 300 \times 10^3 \times 55.00 \times 0.5 = \$8,250,000$$

OPERATING RESERVE COORDINATION

Operating independently of the pool, each operating company would provide operating reserves equal to at least the largest unit installed in each company. As a member of the pool, each company would provide a part of the operating reserves for the pool based on one and one-half times the largest unit in the pool. The following estimated annual benefits are based on a capacity cost of $12.00 per kilowatt-year (determined strictly on judgment).

Method A

This method evaluates the benefits on the basis of existing units in the Southern Company.

Unit	Operating Reserves (MW) Independent	Coordinated
Alabama	880	
Georgia	880	
Gulf	500	1.5 x 880 = 1320
Mississippi	500	
Total Operating Reserve	2760	1320

Annual Benefits = $(2760 - 1320) \times 10^3 \times 12.00 = \$17,280,000$

Method B

This approach is very conservative and assumes that the four operating companies have been independent for several years and as a result have installed the following smaller units for independent operations.

Unit	Operating Reserves (MW) Independent	Coordinated
Alabama	500	
Georgia	700	
Gulf	250	1.5 x 880 = 1320
Mississippi	250	
Total Operating Reserve	1700	1320

Annual Benefits = $(1700 - 1320) \times 10^3 \times 12.00 = \$4,560,000$

The annual benefits from operating reserve coordination should be in the range given by the aforementioned methods and are estimated as follows:

Estimated Annual Benefits = $(17,280,000 + 4,560,000) / 2 = \$10,920,000$

EMERGENCY EXCHANGE

Capacity Exchange

The emergency capacity available to the pool from nonassociated companies is estimated to be 700 MW as listed in FPC Form 12. With each company operating independently, the emergency capacity available to each company would be less than that available to the pool due to tieline restrictions and

reduced diversity and access with neighboring companies. The emergency capacity that would be expected to be available to each company is listed in Column A. The capacity that may be required by each operating company during at least 2 months each year to provide reserves for the largest unit on the company is shown in Column B. The annual benefits shown in Column C are evaluated at a capacity cost of $12.00 per kilowatt-year for 2 months or $2.00 per kilowatt (determined strictly on judgment).

Unit	A Emergency Capacity Available Independent (MW)	B Emergency Capacity Required (MW)	Annual Benefits (dollars)
Alabama	400	700	600,000
Georgia	500	700	400,000
Gulf	175	500	650,000
Mississippi	175	500	650,000
Annual Benefits			$2,300,000

Energy Exchange

In addition to the benefits associated with capacity, records kept on the emergency energy exchange with nonassociated companies, with repayment in kind, indicate that this type of energy exchange has reduced the cost of direct payment for energy by an average of $20/MWh of energy exchanged. During the past year, the energy exchanged was approximately 102,000 MWh. The estimated annual benefits are as follows:

$$\text{Annual Benefits} = 102{,}000 \text{ MWh} \times \$20/\text{MWh} = \$2{,}040{,}000$$

The total annual benefits from emergency capacity and energy exchange are:

$$\text{Estimated Annual Benefits} = 2{,}300{,}000 + 2{,}040{,}000 = \$4{,}340{,}000$$

ECONOMIC DISPATCH AND INTERCHANGE FOR ASSOCIATED COMPANIES

Studies of benefits associated with economically dispatching the four operating companies have shown benefits of approximately $875,000 per year when escalated to the current year.

In addition to the benefits due to the economic dispatch, benefits are realized from the free flow of interchange among the associated companies resulting from the pool economic dispatch. Previous studies have shown benefits from these interchanges of approximately $2.80/MWh of energy interchanged. During the previous year, approximately 5,700,000 MWh of

energy were interchanged between the companies in the pool. The estimated annual benefits were approximately $15,960,000.

The total annual benefits from economic dispatch and interchange are as follows:

$$\text{Estimated Annual Benefits} = 875{,}000 + 15{,}960{,}000 = \$16{,}835{,}000$$

PEAK-HOUR DIVERSITY

The diversity of the peak-hour demands of the four companies in the pool has averaged approximately 200 MW over the last 5 years. The requirement for installed capacity is reduced by the amount of the diversity. On the basis of the approximate embedded cost of generation for the Southern electric system of $55.00 per kilowatt-year, the annual benefits are as follows:

$$\text{Estimated Annual Benefits} = 200 \times 10^3 \times 55 = \$11{,}000{,}000$$

ILLUSTRATION OF MAGNITUDE OF POOLING TRANSACTIONS

In addition to the examples of benefits shown, Tables 2 through 6 show the extent to which the Southern electric system is effecting transactions with other entities.

EVALUATION BY COORDINATION GROUP OF ITS CURRENT STATUS

The managements of the operating companies and SCS are convinced that the coordinated planning and operations that have occurred over many years have resulted in better service to the public at a lower cost than if the respective operating companies were to plan their electric systems in isolation and undertake to operate independently. Through the benefits of coordination provided through SCS, these companies are expected to continue to find methods and procedures to improve their economies and conserve their resources.

TABLE 2--Magnitude of Transactions in 1978

		Energy (kWh)		Payment (dollars)	
		Delivered	Received	Received	Made to pool
PURCHASES AND SALES					
Associated companies					
Monthly payment				36,420,518.00	36,420,518,00
Month-end adjustment		67,862,783	67,862,783	1,548,280.70	1,548,280.70
Interchange energy		5,674,306,000	5,674,306,000	126,993,144.51	126,993,144.51
Pool energy		10,971,130	10,971,130	317,579.86	317,579.86
Total		5,753,139,913	5,753,139,913	165,279,523.07	165,279,523.07
Nonassociated companies	Energy				
TVA	Economy	24,551,000	1,092,000	984,109.11	49,283.03
	Emergency	2,747,000	x	161,310.44	x
Florida Power Corp.	Economy	x	62,782,000	x	2,043,773.49
	Emergency	x	556,000	16,960.93	18,493.01
Duke Power Co.	Economy	x	1,400,000	x	47,862.50
	Emergency	x	800,000	x	45,580.46
South Carolina E. & G. Co.	Economy	x	47,331,000	x	1,221,497.19
	Emergency	333,000	1,363,000	16,304.01	70,904.79
Miss. Power & Light Co. (Mid-South)	Economy	x	30,050,000	x	1,061,182.50
	Emergency	5,513,000	x	296,065.59	x
Total		33,144,000	145,374,000	1,474,750.08	4,558,576.97
INTERCHANGE TRANSACTIONS					
Nonassociated companies	Exchange				
TVA	Seasonal	433,200,000	433,200,000		
	Emergency	47,792,000	38,643,000		
	Inadvertent	69,816,225	52,563,518		
Florida Power Corp.	Emergency	4,545,000	406,000		
	Inadvertent	3,591,000	2,390,000		
Duke Power Co.	Emergency	39,222,000	28,798,000		
South Carolina E. & G. Co.	Emergency	7,238,000	11,726,000		
Miss. Power & Light Co. (Mid-South)	Emergency	17,581,000	8,667,000		
Total		622,985,225	576,393,518		
Grand total		6,409,269,138	6,474,907,431	166,754,273.15	169,838,100.04

TABLE 3--Magnitude of Transactions from January 1979 through June 1979

		Energy (kWh) Delivered	Energy (kWh) Received	Payment (dollars) Received	Payment (dollars) Made to pool
PURCHASES AND SALES					
Associated companies					
Monthly payment		0	0	13,017,855.00	13,017,855.00
Month-end adjustment		29,093,017	29,093,017	627,895.09	627,895.09
Interchange energy		2,602,667,000	2,602,667,000	55,796,961.89	55,796,961.89
Pool energy		24,632,000	24,632,000	511,230.15	511,230.15
Total		2,656,392,017	2,656,392,017	69,953,942.13	69,953,942.13
Nonassociated companies	Energy				
TVA	Economy	140,813,000	0	3,260,633.62	0
	Emergency	0	0	0	0
Florida Power Corp.	Economy	439,437,000	0	11,543,403.41	0
	Emergency	0	0	0	0
Duke Power Co.	Economy	16,683,000	0	410,125.38	0
	Emergency	0	0	0	0
South Carolina E. & G. Co.	Economy	150,000	100,000	3,314.30	2,184.60
	Emergency	0	3,019,000	0	93,078.18
Miss. Power & Light Co.	Economy	1,514,587,000	0	32,109,824.58	0
(Mid-South)	Emergency	5,469,000	0	247,546.66	0
Total		2,117,139,000	3,119,000	47,574,847.95	95,262.78
INTERCHANGE TRANSACTIONS					
Nonassociated companies	Exchange				
TVA	Seasonal	273,600,000	182,400,000		
	Emergency	2,267,000	22,742,000		
	Inadvertent	34,349,813	27,916,722		
Florida Power Corp.	Emergency	4,375,000	0		
	Inadvertent	586,000	1,831,000		
Duke Power Co.	Emergency	3,192,000	16,399,000		
South Carolina E. & G. Co.	Emergency	101,000	1,492,000		
Miss. Power & Light Co. (Mid-South)	Emergency	21,979,000	16,824,000		
Total		340,449,813	269,604,722		
Grand total		5,113,980,830	2,929,115,739	117,528,790.08	70,049,204.91

TABLE 4--Purchases and Sales with Nonassociated Utilities During 1978

	Energy (kWh)		Payment (dollars)	
	Delivered to nonassoc. utility	Received from nonassoc. utility	Received from nonassoc. utility	Made to nonassoc. utility
ALABAMA				
Alabama Electric Cooperative	342,302,334	17,595,410	10,533,937.72	197,710.38
GEORGIA				
Savannah Electric & Power Company				
Fixed charge	0	0	1,300,400.00	0
Energy	91,628,500	1,350,800	2,754,241.26	71,186.19
Total	91,628,500	1,350,800	4,050,641.26	71,186.19
Crisp County Power Commission				
Fixed charge	0	0	214,803.25	0
Energy	65,925,972	915,473	974,522.37	6,409.58
Total	65,925,972	915,473	1,189,325.62	6,409.58
South Carolina Electric & Gas Company				
Fixed charge	0	0	0	1,753,498.32
Fuel	0	499,088,000	0	7,378,240.70
Total	0	499,088,000	0	9,131,739.02
Oglethorpe Power Corporation				
Capacity charge	0	0	0	19,724,454.00
Energy charge*	0	2,646,498,620	0	31,688,454.00
Total	0	2,646,498,620	0	51,413,313.16
Municipal Electric Authority of Ga.				
Capacity charge	0	0	0	9,022,722.00
Energy charge*	0	1,128,608,158	0	12,526,908.27
Total	0	1,128,608,158	0	21,549,630.27
City of Dalton				
Capacity charge	0	0	0	50,071.00
Energy charge*	0	26,897,939	0	307,872.09
Total	0	26,897,939	0	357,943.09
Georgia Total	157,554,472	4,303,358,990	5,243,966.88	82,530,221.31
MISSISSIPPI				
South Mississippi Electric Pwr. Assoc.	49,938,000	90,206,000	1,925,646.85	3,306,379.05
Grand total	549,794,806	4,411,160,400	17,703,551.45	86,034,310.74

*Does not include partial requirements supplied by Georgia.

TABLE 5--Purchases and Sales with Nonassociated Utilities from January 1979 through June 1979

	Energy (kWh)		Payment (dollars)	
	Delivered to nonassoc. utility	Received from nonassoc. utility	Received from nonassoc. utility	Made to nonassoc. utility
ALABAMA				
Alabama Electric Cooperative	5,846,730	6,365,670	1,185,664.39	43,189.26
GEORGIA				
Savannah Electric Power Company				
Fixed charge	0	0	244,400.00	0
Energy	98,882,000	0	2,530,461.15	0
Total	98,882,000	0	2,774,861.15	0
Crisp County Power Commission				
Fixed charge	0	0	121,227.12	0
Energy	26,491,293	224,938	497,329.94	466.26
Total	26,491,293	224,938	528,557.06	466.26
South Carolina Electric & Gas Company				
Fixed charge	0	0	0	185,966.79
Fuel	17,000	61,762,000	408.00	935,144.72
Total	17,000	61,762,000	408.00	1,121,111.51
Oglethorpe Power Corporation				
Capacity charge	0	0	0	10,115,000.00
Energy charge*	0	1,161,112,030	0	16,388,813.87
Total	0	1,161,112,030	0	26,503,813.87
Municipal Authority of Georgia				
Capacity charge	0	0	0	4,846,534.00
Energy charge*	0	486,135,985	0	6,950,189.36
Total	0	486,135,985	0	11,796,723.36
City of Dalton				
Capacity charge	0	0	0	0
Energy charge*	0	4,409,416	0	102,975.80
Total	0	4,409,416	0	102,975.80
Georgia Total	125,390,293	1,713,644,369	3,303,826.21	39,525,090.80
MISSISSIPPI				
South Mississippi Electric Pwr. Assoc.	2,288,000	21,544,000	257,368.18	1,763,405.96
Grand total	133,525,023	1,741,554,039	4,746,858.78	41,331,686.02

*Does not include partial requirements supplied by Georgia.

TABLE 6--Purchases and Sales with Southeastern Power Administration[1]

	Energy (kWh)		Payment (dollars)	
	Delivered to SEPA	Received from SEPA	Received from SEPA	Made to SEPA
1978				
Capacity charge	0	0	0	8,007,710.04
Wheeling and integration	0	0	2,598,957.48	0
Preference customer allocation	0	2,074,649,661[2]	0	0
Carter's pump storage	368,572,000	255,976,000	0	0
Total	368,572,000	2,330,625,661	2,598,957.48	8,007,710.04
JAN. 1979--JUNE 1979				
Capacity charge	0	0	0	3,981,769.30
Wheeling and integration	0	0	1,299,478.74	0
Preference customer allocation	0	1,028,798,873[2]	0	0
Carter's pump storage	117,513,000	84,403,000	0	0
Total	117,513,000	1,113,201,873	1,299,478.74	3,981,769.30

[1]Values shown are the totals for the four operating companies.

[2]Preference customer energy delivered by company for which no dollars are exchanged. Excess SEPA generation, above the preference customer allocation, is placed in a storage account by the company and is withdrawn at a later time at the request of SEPA.

CHAPTER 7
FLORIDA SUBREGION

AREA DESCRIPTION

The Florida Subregion of the Southeast Region is most commonly referred to as Peninsular Florida. (See Figure 12.) It is bordered on the west by the Gulf of Mexico and the Apalachicola River, and on the east by the Atlantic Ocean. Its northern border is the Georgia State line. Peninsular Florida has a land area of approximately 58,000 square miles and supports a population of over 8.5 million people. The east coast of Florida is very densely populated, as is the west coast from Tampa Bay south to Ft. Myers. With the exception of the Orlando, Lakeland, Gainesville, and Tallahassee areas, the remainder of Peninsular Florida is either very rural or areas of an environmental significance that precludes further development.

AREA CHARACTERISTICS INFLUENCING COORDINATION

The largest factor influencing coordination in Peninsular Florida is the large number of electric utilities: 51 different investor-owned, municipally owned, and cooperatively owned electric utilities varying in size from 2 MW of peak demand to nearly 9000 MW of peak demand. The majority of the total retail energy requirement within the area is met by three investor-owned utilities that collectively produce 78 percent of the peninsula's electric energy. Municipally owned systems supply 18 percent of the electric requirements, and rural electric cooperatives supply the remaining 4 percent. Table 7 is a list of the electric utility systems in Florida.

Several characteristics unique to Florida have caused or influenced coordination among the subregion's electric utilities. The peninsular nature of the State has obviously limited interconnections and tielines to the northern border with Georgia and the northwest border to the panhandle. At present, the interstate tielines, owned solely by the Florida Power Corporation, have an installed interconnection capability of approximately 300 MW.* An additional 230-kV tie was connected in December 1979, by the Florida Power & Light Company through northeast Florida near Jacksonville, into Georgia. This line is anticipated to raise the installed interconnection capability to nearly 600 MW*. The strengthening of an interconnection from the Florida Power Corporation to the Gulf Power Company in the west, to the Panhandle of Florida, and a proposed 230-kV line from

*This value is without consideration of scheduled interchanges.

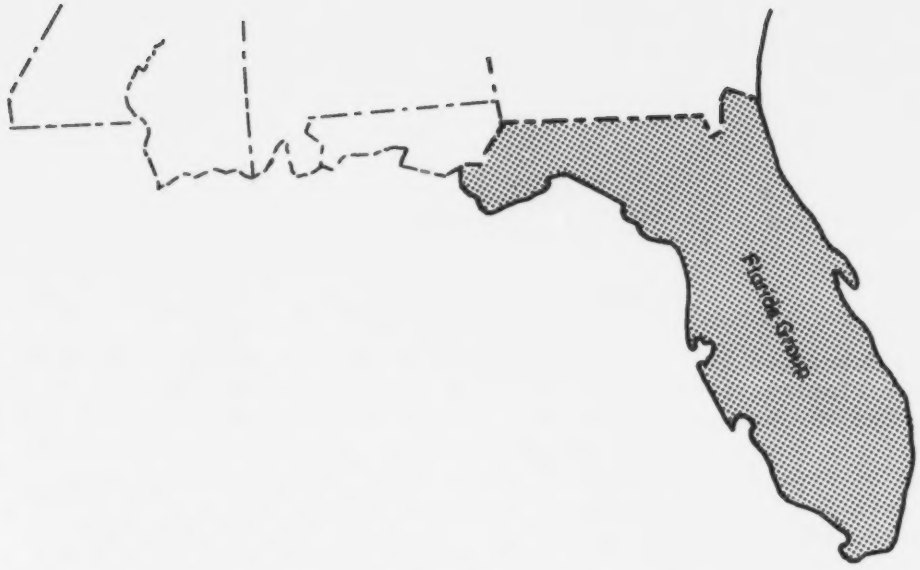

FIGURE 12--The Florida Subregion

Tallahassee into Georgia could significantly increase this transfer capability within the next 4 years. These activities are, and will continue to be, coordinated with the Southern Company.

Coordination among electric utilities in Florida has been practiced for many years and has often been relied upon during natural disasters, such as hurricanes and tornadoes. Furthermore, Florida has the highest isokeraunic levels in the United States. During disasters, coordination exists even to the extent of using the manpower of many systems throughout the State to repair the system or systems ravaged by storm.

The profile of energy use in Florida is also unique. The characteristics of the load are mainly those of "all-electric" residential customers who depend almost entirely on electricity for their household energy. Residential sales constitute 40 percent of all electric energy sold, and commercial sales constitute 28 percent. Florida is thus the seventh largest State in number of residential customers and the third largest in residential energy sales, exceeded only by California and Texas.

Florida's 1375 miles of coastline and it's excellent ports contribute to its heavy dependence on residual oil for the generation of electricity. Florida burned 73 million barrels of residual oil in the generation of electricity during 1978, and is anticipated to burn over 80 million in 1979. During 1978, residual oil, distillate oil, and natural gas were used to generate 65 percent of the total electrical energy requirements in Florida. Nearly all of the 73 million barrels of residual oil and 3 million barrels of distillate oil used in 1978 delivered by way of water transportation.

TABLE 7--F

Investor-owned systems (all generate)	No
1. Florida Power Corporation	1
2. Florida Power & Light Company	2
3. Florida Public Utilities Company	3
4. Gulf Power Company	4
5. Tampa Electric Company	5
6. Reedy Creek Utility Company, Inc.	6
	7
Generating municipal systems	8
	9
1. Fort Pierce Utilities Authority	10
2. City of Gainesville	11
3. City of Homestead	12
4. Jacksonville Electric Authority	13
5. City of Key West Utility Board	14
6. City of Kissimmee	15
7. City of Lakeland	16
8. Lake Worth Utilities Authority	17
9. Utilities Commission of New Smyrna Beach	18
10. Orlando Utilities Commission	No
11. City of St. Cloud	
12. Sebring Utilities Commission	1
13. City of Starke	2
14. City of Tallahassee	3
15. City of Vero Beach	4
16. City of Wauchula	5
	6
Generating rural electric cooperatives	7
	8
1. Florida Keys Electric Cooperative	9
2. Seminole Electric Cooperative	10
	11
Generating--Other	12
	13
Southeastern Power Administration (Jim Woodruff Dam)	14
	15

lorida Electric Utility Industry

ngenerating municipal systems

. City of Alachua
. City of Bartow
. City of Blountstown
. City of Bushnell
. City of Chattahoochee
. City of Clewiston
. City of Fort Meade
. City of Green Cove Springs
. City of Havana
. City of Jacksonville Beach
. City of Lake Helen
. City of Leesburg
. City of Moore Haven
. City of Mount Dora
. City of Newberry
. City of Ocala
. City of Quincy
. City of Williston

ngenerating rural electric cooperatives

. Central Florida Electric Cooperative
. Choctawhatchee Electric Cooperative
. Clay County Electric Cooperative
. Escambia Electric Cooperative
. Glades Electric Cooperative
. Gulf Coast Cooperative
. Lee County Electric Cooperative
. Peace River Electric Cooperative
. Sumter Electric Cooperative
. Suwannee Valley Electric Cooperative
. Talquin Electric Cooperative
. Tri-County Electric Cooperative
. West Florida Electric Cooperative
. Withlacoochee River Electric Cooperative
. Okefenokee Rural Electric Membership Corporation

The bulk power transmission system (or grid) within Peninsular Florida (Figure 13) conforms to the peninsular shape and is owned principally by five electric utilities: Florida Power & Light Company, Florida Power Corporation, Tampa Electric Company, Orlando Utilities Commission, and the City of Lakeland. Nearly all other systems radiate from the interconnected grid of these five systems. Among these five, Florida Power & Light Company and Florida Power Corporation have the major share.

HISTORY OF POWER POOLING

During the rapid growth period of the 1940's and 1950's, Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company built relatively low-capacity interties to deal with emergency outages. The cities of Kissimmee and St. Cloud also built a low-capacity intertie during the 1950's, as did the cities of Fort Pierce and Vero Beach.

In 1959, Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company formed the Florida Operating Committee to increase coordination and provide emergency assistance. Very soon thereafter, they were joined by the Jacksonville Electric Authority and the Orlando Utilities Commission, which soon became full members of the Operating Committee. During the mid-1960's, these five utilities, joined by the City of Lakeland, moved to the next level of coordination when they established an operating reserve policy. Although utilities initially had varying requirements based on size, they soon developed a uniform procedure for providing spinning and supplemental operating reserves for their systems. Ultimately, they provided reserve collectively for the largest contingency outage. These Operating Committee systems also entered into agreements with each other for firm long-term power exchanges in the hopes of staggering generation, construction, and facility planning. During this period, interties were sized for both firm and emergency power exchanges.

Between 1959 and 1972, the Operating Committee developed many procedures for increasing reliability. In addition to daily operating reserve policies, policies and practices were formulated for coordinating maintenance scheduling, reviewing long-range generation and transmission plans, coordinating underfrequency and tieline relays, and establishing emergency and normal communication links. The major product of this coordination, the Operating Committee Handbook, is continually revised and amended and is still in use. The handbook contains procedures that meet or exceed NERC operating committee (formerly NAPSIC) guidelines.

Interconnections between municipal and investor-owned utilities were not automatic or without their turbulent periods. Over the years, many municipal systems have found it necessary to litigate issues before the courts and regulatory authorities to secure bulk power supply arrangements. This necessity continues. The Gainesville Municipal Electric System, for example, commencing in 1964, attempted to secure interconnections with the Florida Power Corporation and then the Florida Power & Light Company, to participate in interconnected operations and thereby, discontinue operating as an isolated system. Gainesville, following extensive litigation resulting in a U.S. Supreme Court decision in 1971, finally interconnected with Florida Power Corporation in July 1973. One of Gainesville's major contentions

FIGURE 13--Florida Subregion Bulk Power Transmission Network

through this period of litigation was that it should not have to pay a standby charge to back the loss of its largest generating unit. Gainesville was soon admitted to the Florida Operating Committee, as were Tallahassee, Fort Pierce, Vero Beach, and Homestead. Membership requirements are being revised to include New Smyrna Beach and Sebring on the Operating Committee.

In 1972, the executives of the utilities who were members of the Florida Operating Committee, established the Florida Electric Power Coordinating Group (FCG) and opened membership to all Florida utilities. The current membership of the FCG is given in Table 8. During the next year, several reports were prepared and published on recent outages in Florida that had placed the Florida utilities in the national spotlight.

The Florida Legislature also assisted in promoting coordination by extending the Florida Public Service Commission's (FPSC) authority to review utilities' generating capacity expansion plans, and by passing the Florida Electrical Power Plant Siting Act in October 1973. The siting act requires each generating utility to submit annually to the Department of Community Affairs, a 10-year plan for generating units and associated transmission lines. It also requires the FPSC to assess the present and future need for generating capacity at each site and to participate in all site certification hearings.

The Florida Legislature continued the next year by passing the Florida Grid Bill, effective July 1974. This bill gave the FPSC jurisdiction over planning, development, and maintenance of a coordinated electric power grid system throughout Florida. The FPSC regulatory jurisdiction was also extended to include municipal utilities and rural electric cooperatives.

The FPSC continues to be a major force in increasing coordination among the Florida utilities. In February 1974, the FPSC commissioned a consulting firm to develop an approach for peninsulawide generation and transmission expansion planning. The consulting firm identified major areas where grid planning studies should be conducted. In June 1975, the FPSC requested and the FCG agreed to undertake a joint generation planning study. This study eventually became part of the FPSC's 1976 Order No. 7080. This expansion planning study was conducted by the 12 utilities represented on the FCG System Planning Committee, with assistance from the FPSC and FCG staffs. The estimated cost of the study, including man-hour costs, was $375,000. The study was inconclusive as to the desirability of joint expansion planning and construction; but it raised substantial interest in joint planning among certain utilities. For example, Florida Power Corporation sold 10 percent of its Crystal River 3 nuclear unit to 10 municipals and cooperatives, and the cities of Orlando and Lakeland have entered into a joint project for a coal-fired generation unit to become operable in 1981. Two joint coal-fired units between Florida Power & Light Company and the Jacksonville Electric Authority are also in the planning stage.

During the period when the generation expansion planning study was being conducted, the FPSC enhanced the potential attractiveness of economy interchange by revising the definition of purchased power in the Florida Fuel Cost Recovery Clause. Before this change in June 1977, investor-owned utilities were allowed to recover only the exact fuel cost component of the energy purchased through economy interchange agreements. The new definition allowed a utility purchasing economy interchange energy to recover the total

TABLE 8--FCG Membership

Investor-Owned (6)
- Florida Power & Light Company
- Florida Power Corporation
- Florida Public Utilities Company
- Gulf Power Company
- Reedy Creek Utility Company
- Tampa Electric Company

Municipals (18)
- City of Bushnell
- Fort Pierce Utilities Authority
- Gainesville/Alachua County Regional Utilities Board
- City of Homestead
- Jacksonville Electric Authority
- City of Key West Utility Board
- City of Kissimmee
- Lake Worth Utilities Authority
- City of Lakeland
- City of New Smyrna Beach Utilities Commission
- City of Ocala
- Orlando Utilities Commission
- City of Quincy
- City of St. Cloud
- Sebring Utilities Commission
- City of Starke
- City of Tallahassee
- City of Vero Beach

Cooperatives (13)
- Central Florida Electric Cooperative
- Choctawhatchee Electric Cooperative
- Clay Electric Cooperative
- Glades Electric Cooperative
- Lee County Electric Cooperative
- Okefenokee Rural Electric Membership Corporation
- Peace River Electric Cooperative
- Seminole Electric Cooperative
- Sumter Electric Cooperative
- Suwannee Valley Electric Cooperative
- Talquin Electric Cooperative
- Tri-County Electric Cooperative
- Withlacoochee River Electric Cooperative

cost of such energy through its fuel adjustment clause. The new definition encourages the sale of economy energy at a price that is attractive to both the buyer and seller.

As a result of the FPSC's new definition and possibly some other factors, economy interchange savings realized by FCG Operating Committee utilities increased nearly twofold between June 1977 and July 1977.

Now stimulated in the interest of economy interchange, the FPSC asked the FCG to conduct a relatively simple simulation for 1 hour to determine the maximum economy interchange that could have occurred versus the amount that did occur. The results of the 1-hour simulation indicated that $1053 in total savings could have been realized and $535 in savings were actually realized during the randomly selected hour.

The FPSC's awareness of and interest in potential savings caused FCG members to increase economic interchange transactions. For example, in February 1978, the month immediately following the FPSC's 1-hour simulation study, actual savings from the economy interchange transactions increased to over $1.6 million (from $900,000 in January). The utilities achieved this increase in savings through a statewide telephone system to exchange buy and sell quotes for economy energy. To accelerate the exchange of buy and sell quotes, the FCG implemented a manual energy broker arrangement using a teletype system in March 1978. After evaluating its performance, the participants decided to continue the manual arrangements until an automated system could be implemented (see FCG--Power Broker Study, August 1978). In February 1979, the system was automated. Because of the relatively simple nature of this arrangement, only bilateral interchange and transmission agreements were required. The present energy broker system is discussed in detail later.

After the conclusion of the Peninsular Florida generation expansion planning study, and before the implementation of a broker system, the FCG undertook, under the requirements of FPSC Order No. 7080, a central dispatch study for all Peninsular Florida generating electric utilities wishing to participate. In this ongoing study, the FCG is attempting to determine the savings for each utility that would result from the central commitment and dispatching of all generating units versus the independent dispatching of those same units by each utility. These savings are being determined by studying a simulated hour-by-hour central dispatch of all these units for 1978. By contrasting the cost of operations under the simulated central dispatch with the adjusted 1978 costs as dispatched, the FCG hopes to determine the potential fuel cost savings resulting from the central dispatch scheme. These estimates will be a major factor in determining whether a central dispatch system should replace the automated broker system. This study was completed on May 14, 1980.

HISTORY OF MUNICIPAL COORDINATION

The first example of a preplanned coordinated power supply development between a municipal system and an investor-owned utility within the State occurred in the 1972-73 period when the Tallahassee Electric System and the

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Florida Power Corporation conducted a study that led to the city's purchasing a short-term firm power supply from the Florida Power Corporation. Tallahassee later constructed a generating unit larger than it could otherwise justify and sold short-term firm capacity and energy to Florida Power Corporation from the unit. Before that, the Orlando Utilities Commission constructed generating units larger than were needed to serve its own system requirements and sold surplus firm power to other utilities on an after-the-fact basis, rather than a preplanned basis.

A major deterrent to further municipal system coordination and joint ownership with private utilities was the prevention of such an activity by the Florida Constitution. Pursuant to a constitutional amendment passed in 1974, the State constitution was amended to alleviate such restrictions and, during the 1975 session of the Florida Legislature, the Joint Power Act was passed and implemented with provisions for amending the State constitution. Under this act, municipalities also received the authority to form an agency to act in their behalf in the financing, acquisition, management, operation, and utilization of generation and transmission projects, including joint projects with private utilities. To that end, the Florida Municipal Power Association (FMPA) was created in 1978. Today, the FMPA's membership includes 26 of the 34 municipal systems in Florida.

Additional restrictions were removed in 1979 by legislation that authorized the FMPA to issue bonds for financing or refinancing the cost of joint electric power supply projects.

In February 1979, a preliminary power supply study for FMPA identified potential power supply alternatives available to FMPA. This study also addressed potential transmission system arrangements within Florida to permit access to various power supply alternatives by FMPA members. FMPA actively continues to pursue transmission and generation supply alternatives and recently proposed a joint transmission system to the technical advisory group (TAG) of the Florida Electric Power Coordinating Group. This proposal and several alternatives are being studied and considered.

With respect to improvements within Florida, FMPA maintains that Peninsular Florida should have a fully integrated power pool in which all the electric utilities could engage in coordinated planning, construction, and ownership of large-scale generation and transmission facilities and make maximum use of existing and planned generating resources under uniform and equitable terms and conditions. These conditions would include, but not be limited to: equalized reserves; exchanges for all types of power and energy including emergency, scheduled maintenance, economy, secondary, firm, and reserve, and all types of capacity backup services; full access to the Peninsular Florida transmission system to facilitate such transactions at reasonable and uniform charges for such exchanges anywhere in the integrated system; and centralized economic dispatch of all units in Peninsular Florida against the total system load, with after-the-fact accounting of the sales and purchases for economy and secondary energy exchanges. All of these conditions could increase the economic benefit and well-being of all such utilities, large and small, and would enhance the competitive viability of all the systems in the wholesale bulk power supply and retail markets encompassed by Peninsular Florida.

HISTORY OF RURAL ELECTRIC COOPERATIVES COORDINATION

Testimony to the coordination and cooperation among cooperatives in Florida is the Seminole Electric Cooperative. Seminole is an 11-member generation and transmission cooperative formed in 1948 to handle rate negotiations for power purchased by members from other utility companies.

By late 1973, uncertainties about future supply caused these cooperatives to redesignate Seminole's purpose as providing its members-owners with adequate reliable electrical energy at the lowest possible cost. To do so, the cooperatives established contracts designating Seminole as their power supplier. At present, Seminole has almost no self-generation, although it owns 14 MW of a generator operated by Florida Power Corporation. It is also actively negotiating for approximately 50 MW ownership of another unit.

After research into practical alternatives, Seminole committed itself to constructing two 600-MW coal-fired units at a site near Palatka, Florida. The first unit will be operational in 1983 and the second in 1985. At that time, Seminole will be providing members with about half of their requirements, and further efforts will be underway to meet the additional needs of the member systems.

RESPONSIBILITIES OF POOL MEMBERSHIP

FCG has been perceived as an evolving power pool in Florida, particularly Peninsular Florida, by the Department of Energy and the National Electric Reliability Council. Although many are proud of their coordination efforts to date, few would deny that much more is to be done.

COORDINATION OF PLANNING

In Peninsular Florida, the coordination of planning efforts is the responsibility of the System Planning Committee of FCG. The System Planning Committee is structured so that it includes the major generating electric utilities in Peninsular Florida in its membership and provides for collective membership of municipals and rural electric cooperatives not qualifying for membership singly or alone. Gulf Power Company (a member of Southern electric system) also attends and participates in committee activities as an observer.

Pursuant to the bylaws of FCG, the System Planning Committee is "...charged with the responsibility of actively coordinating the planning of the electric bulk power supply system in Florida." This statement is interpreted to include exchanging information with respect to planning among FCG member systems and other organizations; investigating and determining if the planned and existing generating facilities and bulk power transmission system are adequate and reliable; and recommending to the FCG members corrective actions concerning the planning, design, and operation of the systems as required to ensure an adequate and reliable electric power supply in Florida consistent with technological advances, environmental standards, and economics.

Because of the magnitude and expense of the studies required of the planning committee, its members stress the importance of making maximum use of its resources of manpower and money. A detailed budget has become a valuable tool in achieving this objective. The committee establishes appropriate goals for the year annually, in its budgetary process. These goals are generally in the areas of load-flow analysis, transient stability analysis, reliability analysis of the generation system, load and energy forecasting, regional coordination studies, FPC Order 383* support, maintenance of an 11-year load-flow data base, studies of spinning reserve requirements, and other topics as required.

During this budgetary process, a scope document is prepared for each project and task force members are assigned in an attempt to balance the contributions of the committee members. Expenses incurred in all the studies conducted by the task forces are recorded and reported monthly to the FCG office. From these data, a current accounting of all the expenses is maintained. These expenses include costs associated with professional and nonprofessional man-hours, travel, duplicating, computer, and miscellaneous expenses. At the end of the fiscal year, these expenses are reconciled with previously determined allocation factors, and invoices are rendered to those who have not contributed manpower in proportion to their allocation; refunds are made to those utilities that have contributed beyond their predetermined obligation.

The Data Bank Task Force is charged with updating and maintaining a representation of the State bulk power transmission and generation system, including projected loads for the present year and the next 10 years. To do this updating, it collects and merges load-flow data from each participating utility and the Southern Company system. (See Chapter 6.) Once merged, these load-flows are solved for base case conditions and made available for use as a State load-flow for several of the other task forces, as well as for any member system wishing to conduct internal studies.

The Transient Stability and Spinning Reserve Task Force is charged with evaluating the system response of Peninsular Florida. It also investigates methods for satisfying spinning reserve requirements, as defined in the Operating Committee Handbook, and explores suitable alternatives to this procedure that may result in reduced system costs and improved response to disturbances.

The FPC Order 383-4 Support Task Force, acting on behalf of the Florida Subregion of the Southeastern Electric Reliability Council (SERC), assembles data and studies results each year as required to satisfy Appendix A-1 of Order 383-4. The FCG staff is charged with compiling and submitting this report and relies on this task force for assistance.

The Load and Energy Task Force exchanges information on load and energy forecasting techniques and addresses potential impacts of new technology and policies on utilities' load and energy projections. It also provides a common historical data base for responding to various governmental agencies and industrial organizations. To this end, it annually updates and publishes the Load Diversity Study.

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*Under the Federal Power Commission (now the Federal Energy Regulatory Commission) Docket R-362, Order 383, the regional reliability council's annual report proposed generating capacity additions for the next 10 years.

A task force also exists to coordinate and participate with the Virginia-Carolinas-Southern-Tennessee Valley Authority (VST) Studies Group each year. Florida participates in a passive role by providing data to the VST data bank for both study and nonstudy years. This participation allows FCG to determine on a yearly basis and establish in an orderly fashion the maximum transfer import-export capabilities of exchange between the Florida and Southern Subregions in both normal and contingency conditions. This study also establishes the limiting facilities in such transfers.

The Transmission Task Force establishes the basis necessary to coordinate the bulk transmission expansion in Peninsular Florida. Its job is to evaluate the performance of the State interconnected system for normal and contingency conditions and identify any weaknesses that may exist. The evaluation includes analysis of the ability of each system to deliver its spinning reserve obligation and steady-state response to single and selected multiple transmission and generation contingencies. Additionally, the task force determines the transfer capability from and into each system. The horizon year of the studies is generally 10 years. As an adjunct to 10-year transmission planning, the long-range transmission study is conducted as necessary to identify potential configurations and patterns for 500-kV interfaces with systems outside Florida. In addition, the task force is responsible for determining the sensitivity of the transmission expansion program to various potential generation expansion strategies, particularly the effects of varying sites.

Starting with mid-1980's conditions, the task force uses a horizon year between 1995 and 2000 to establish a target system. The system is then time-staged at given intervals with heavy bias toward the horizon year target. The tool that has proved to be best suited for this application is a technique based on linear programing. The benefits of linear programing are that a large number of conditions can be examined with reasonable accuracy at a modest expense; to some degree, consideration is given to the optimization of given load generation, operating and design criteria, right-of-way, and other constraints; and interarea transfers are automatically tested.

The Generation Task Force appraises the level of adequacy and reliability of the planned generation system in Peninsular Florida. During this process, they are charged with evaluating industry techniques and preparing a generation reliability analysis of the most recent load forecast and generation expansion plans, as contained in each utility's 10-year plan submitted to the State government. Recent studies have consisted of 10 years of loss of load probability analysis, with consideration given to the uncertainties of each of the variables involved in probability studies, especially demand forecasts and outage rate data.

During fiscal years 1978-79, the studies of the System Planning Committee were estimated and budgeted to cost $248,000. These expenses do not include those of System Planning Committee members meeting as the committee, nor do they include FCG staff and administrative costs.

COORDINATION OF OPERATIONS

Since 1959, the coordination of operations among Florida electric utilities has become increasingly complex. Today, coordinated efforts, apart

from FCG, also exist between the cities of St. Cloud and Kissimmee, the Florida Power Corporation and Sebring, the Florida Power Corporation and Wauchula, and between Vero Beach and Fort Pierce.

By far the greatest effort to coordinate operations exists within the Operating Committee of FCG. This operating committee is the successor to the Florida Operating Committee, established in 1959. The operating practices, principles, procedures, and methods are described in the Operating Committee Handbook. These guidelines and recommendations have evolved over the years and are equal to or more stringent than the NAPSIC operating guides. The Operating Committee, like the System Planning Committee, relies upon a budget for determining the scope of its standing subcommittees and accounting for all expenses.

The Dispatcher Training Subcommittee provides the overall administration, coordination, and scheduling of programs designed to improve overall dispatcher performance. Each year, a dispatcher seminar, held on three occasions to accommodate all dispatchers, reviews the overall dispatcher performance compared to acceptable guidelines and operating criteria. In addition, an attempt is made to determine additional training needs in both new areas of learning, and to review happenings over the past year.

The Energy Broker Administrative Subcommittee provides overall administration, and functions as a board for establishing implementation and operating procedures for brokering of economy interchange.

The Performance Subcommittee provides a coordinated review and evaluation of the performance of the State's interconnected utility systems under normal and disturbance conditions. This subcommittee has established reporting methods, procedures, and forms for building a data base on statewide system performance. It is charged with making detailed investigations and analyses, as required, of specific disturbances or incidents, and reviewing and commenting on procedures, guidelines, policies, and standards for the adequacy and effectiveness of operations.

The Production Subcommittee establishes means and methods for examining outage schedules and provides a valuable forum for the exchange and review of data on statewide unit outages. This review of both the performance of units and the causes for outages of units leads to the operation of a more efficient system. In addition, the frank discussion of plant maintenance problems often results in solutions benefiting all utilities. Discussions and lectures on unit testing, economic production, and central dispatch lead to the more efficient dispatch of each system.

The Relay Subcommittee holds regular semiannual meetings structured to allow the study of unusual performances of relay systems, review of tieline relaying, and preparation of the annual Underfrequency Relay Capability Report. This subcommittee provides the overall understanding, coordination, and scheduling of system relaying philosophies, performance, and settings as they affect the power transfer needs of the transmission system.

OPERATING RESERVES

To ensure reliable operation of the interconnected electrical system, sufficient operating reserves are required to meet power shortages caused by such factors as the failure of generating equipment, failure of transmission

equipment, and insufficient capacity resulting from errors in load forecasting. The Operating Committee has developed procedures for establishing and administering operating reserves for the 13 electric generating utilities in the Operating Committee. The operating reserve policy specifies both spinning reserve levels and daily operating reserve levels for each generating utility. These guidelines require that spinning reserve levels at least equal the peak capacity rating of the largest generating unit in service on the collective systems, and that no more than 16.7 percent of the continuous capability of a single steam unit be used to provide spinning reserve.

In addition to the spinning reserve, supplemental reserve is required and should at least equal the peak capacity rating of the second largest contingency in service. The sum of the spinning reserve and the supplemental reserve constitutes the daily operating reserve. Sharing of this operating reserve by all Operating Committee members lowers the operating costs through more economic allocation and dispatch of units and reduces the online capacity requirements.

FCG uses an allocation formula to determine each utility's share of daily operating and spinning reserve requirements. This formula gives equal weight to two components: each utility's largest generation unit, and its peak load. This method of allocation assigns a proportionally greater reserve requirement to utilities with larger loads, larger generating units, or both.

SCHEDULED MAINTENANCE

A coordinated maintenance program provides flexibility to the participating utilities in allowing them to meet their required loads and operating reserve level. This coordination often requires bilateral short-term firm power exchanges. The Operating Committee utilities supply their schedules of maintenance for generation equipment to the FCG staff as changes occur, so that a current composite schedule is available at any time.

EMERGENCY PROCEDURES

As a member of the Operating Committee, each utility agrees to follow a common emergency procedure that provides for backup power in the case of a major generation and transmission failure. The Energy Control Center of the Florida Power Corporation acts as the central coordinator during normal and abnormal periods. Most FCG emergency procedures are patterned after the NAPSIC guidelines and address issues such as load-shedding, voltage reduction, and underfrequency relaying. The underfrequency relaying program is coordinated annually, and at present results in more than 30 percent of firm load being placed on various steps of underfrequency relaying.

ENERGY BROKER SYSTEM

The history of the energy broker was given previously. Each utility system in the FCG grid determines its unit commitment and dispatches its

units to meet its load in the most economic manner available. In addition, each utility submits hourly quotations of a price and an amount it is willing to buy, and a price and an amount it is willing to sell. These buy and sell quotes are incremental and decremental quotes and are intended to broadly simulate the system's incremental cost curve. Buyers and sellers are matched by a computer system on a high-to-low basis: the highest decremental or avoided cost is paired with the lowest incremental cost, after accounting for transmission charges and losses. The savings resulting from such matchups are shared equally by both utilities. The high-low method for determining economy interchange split savings is a common industry practice. At quarter to the hour, the quoting session is closed by the computer system, and a schedule for the next hour is computed and printed at each dispatch office. Software programs for the energy broker system were written by engineers from the FCG staff and the Orlando Utilities Commission.

The current annual rate of savings from the energy broker system is currently $22 million. The automated system is unique in that it uses bilateral agreements and transmission service agreements as necessary, rather than multilateral agreements. Even though not all nonadjacent FCG participants presently have all the necessary bilateral agreements to allow the absolute maximum savings, economy interchange transactions under the energy broker system are not significantly constrained.

EVALUATION OF STATUS

There are 51 different opinions--as many as there are utilities--on the status of pooling in Peninsular Florida. The central issue of debate is the same issue being debated nationwide--access to transmission. This debate has persisted for 50 years; there is no reason to believe that the FCG will be able to solve the transmission question to the satisfaction of all in the near future. However, a proposal submitted by the FMPA to FCG is being formally evaluated by the member systems of the Technical Advisory Group of FCG, and it is hoped that alternate proposals will be sent forth to be debated. The crucial and pivotal condition placed by nearly all of the operating systems on any proposal to advance pooling is that evident benefits for all must exist. Possibly, the transmission question is moving towards resolution.

FCG is assessing the potential savings to each operating system of a central dispatch scheme. If the central dispatch study, completed in May 1980, exhibits substantial savings above those of the current methods of operation, heavy economic and political pressures will be exerted to form a formal power pool. Such a power pool would possibly employ unit commitment and central dispatch for all of Peninsular Florida.

In the interim, most systems are approaching transmission and service questions with a philosophical view that stresses using the type of transmission service available, despite their opinion of its appropriateness. Those systems have elected to enjoy the savings provided by the energy broker system and other interchange transactions through existing transmission service agreements and wheeling tariffs while they debate the merits of alternate transmission service schemes.

The FPSC has requested that, once the issue of central dispatch is resolved, the FCG investigate the problems of, and solutions available for, long-term energy shortages. The FPSC has suggested that a uniform energy shortage plan be developed that might incorporate the philosophy of serving another system's customers to the detriment of one's own system. This examination is scheduled for the near future.

CHAPTER 8
MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA (MEAG)

AREA DESCRIPTION

The Municipal Electric Authority of Georgia (MEAG) provides electric power services to 46 municipalities and one county (Crisp County) in Georgia. Figure 14 is a map showing the locations of the 47 entities, and Figure 15 shows the integrated transmission system and joint ownership generating plants.

AREA CHARACTERISTICS INFLUENCING COORDINATION

The cities of the area sought State legislation to establish a public entity to enable them to meet the needs of publicly owned electric distribution systems. The act was adopted in 1975, and MEAG was organized in July of that year.

POWER POOL MEMBERSHIP AND ORGANIZATIONAL STRUCTURE

MEAG is a public corporation and an instrumentality of the State of Georgia, created by an Act of the General Assembly in 1975 to provide a dependable source of electric power and energy to political subdivisions of the State of Georgia, which owned and operated the electrical distribution systems on the effective date of the Act.

HISTORY OF POWER POOL ORGANIZATION

As in other parts of the Nation, the majority of the municipal electric systems in Georgia started with their own generation and distribution and always had municipal operation. Some municipalities that may have been supplied by a larger electric company at some time have now broken away; however, all of the systems probably had municipal operations before 1930. Almost all systems at one time or another had their own local generation, which was ultimately retired because of age, and became whole requirements customers of Georgia Power Company (GPC) because of economies of scale. Exclusive of the area supplied by the Tennessee Valley Authority (TVA), the State has 49 municipal electric systems and one county public power district (Crisp County).

FIGURE 14--Participants in MEAG

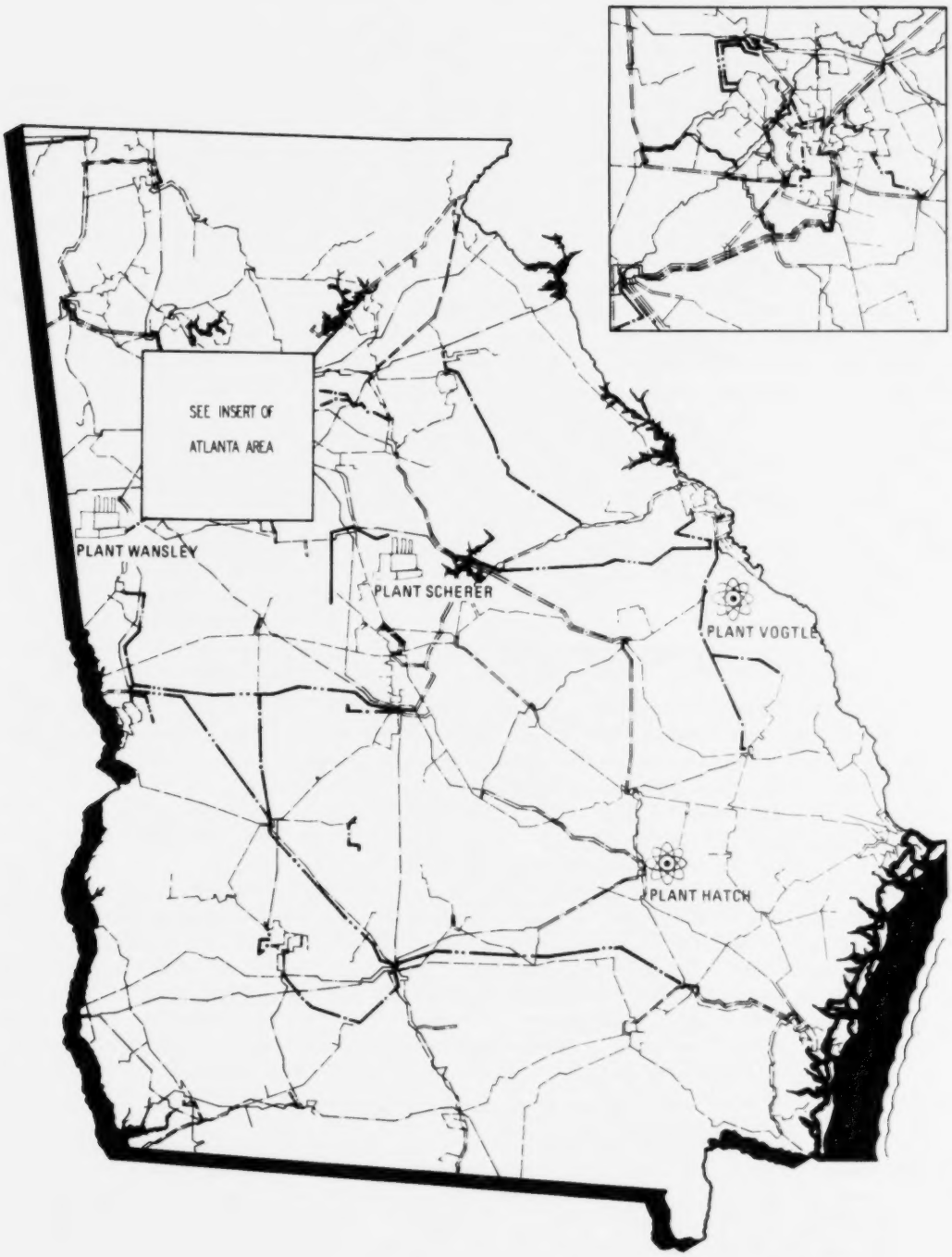

FIGURE 15--The Integrated Transmission System and MEAG Joint Ownership Generating Plants

Since the late 1950's, most of the cities have cooperated on matters of common concern in their electric distribution systems, and have appeared jointly before the Federal Power Commission (now the Federal Energy Regulatory Commission (FERC)) in proceedings on wholesale electric rate increases. In 1972, several cities intervened in the licensing proceedings before the U.S. Atomic Energy Commission (now the Nuclear Regulatory Commission (NRC)), on the planned construction of nuclear-fueled power plants in Georgia by GPC. A settlement was reached with GPC that provided for the sale of a portion of certain nuclear-fueled units to the cities, among others. GPC subsequently elected to negotiate for the sale of interest in other facilities not the subject of the settlement.

As a result of studies of sources of bulk power supply as alternatives to the purchase of their requirements from GPC, the cities sought State legislation to establish a public entity to enable them to meet the needs of publicly owned electric distribution systems. The Act was adopted in 1975, and the Authority was organized in July of that year. Of the 49 municipal electric systems, two elected not to become involved with the purchase of generation, one elected to purchase generation in its own name (the City of Dalton) and 46 cities, plus Crisp County, elected to act jointly through MEAG. The aforementioned NRC Settlement Agreement, coupled with an adverse financial position after 1974, led GPC to negotiate portions of their transmission system together with agreements for committees to govern the joint affairs of the joint owners.

POWER POOL AGREEMENTS AND CONTRACTS

The NRC Settlement Agreement states that GPC is responsible for having a partial service requirement for those systems that were involved in the NRC hearing and have elected to enter the generation and transmission business. The NRC settlement also places a responsibility on GPC to extend interconnection agreements and a variety of specified service agreements to the new generation and transmission (G & T) entities. The partial service requirement is being fulfilled through a partial requirement rate, which has been filed with FERC and is utilized by MEAG, Oglethorpe, and Dalton. (The cities of Acworth and Hampton, which elected not to become members of MEAG, are supplied under whole requirements contracts also filed with FERC.) The requirement to provide interchange service schedules between GPC, MEAG, Oglethorpe, and Dalton has not been effected at this time and could be an appropriate part of a Georgia Pool.

RESPONSIBILITY OF POOL MEMBERSHIP

MEAG supplies exclusively the bulk power requirements of the 47 political subdivisions in excess of their allocations of federally generated power purchased under contracts with the Southeastern Power Administration (SEPA), and in excess of their own locally owned generation.

COORDINATION OF PLANNING

A contract provided for the establishment of a Joint Committee for Planning and Operations to administer the contracts of the joint owners of generation and transmission within the State of Georgia. The Joint Committee for Planning and Operations has established numerous subcommittees, including one for planning. Although this committee structure is fairly new, it is functioning quite well and will probably continue to do so if a continuing relationship is based on the formation of a pool, the continuation of the seller-customer relationship under the PR (partial requirements) tariff, or the administration of interconnection agreements and their associated service schedules.

The principal activities of the subcommittee for plan[illegible] o far coordinating load forecasts, and constructing bulk power facilities for serving new and expanding loads. Even though MEAG, Oglethorpe, and the City of Dalton are joint owners of the Integrated Transmission Syster[illegible] date has not permitted their involvement in planning studies affecti[illegible] interface of the Integrated Transmission System with Florida and with the Carolinas. Probably MEAG, Oglethorpe, and Dalton will be responsible for a proportionate share of the costs of whatever facilities GPC decides to install.

GPC develops a long-range generation plan associated with each long-range load forecast. Individually, Oglethorpe and MEAG are performing long-range generation plans to study participation in joint development, as compared with other independent options. On an individual basis, MEAG is pursuing the development of low-head hydroelectric projects, and cogeneration installations with wood product companies. Whatever plans MEAG determines to be appropriate will be discussed with the other joint owners, and an analysis of reserves will play a part in the timing of the construction of new facilities.

SHARING OF DEVELOPMENT COSTS

The Integrated Transmission System is owned by the four participating entities according to the ratios of their noncoincident capacity demands. These ratios are used to assign the responsibility of the Integrated Transmission System on the basis of the undepreciated book cost of all facilities from the high-side of generator transformers to the distribution substations, provided that the distribution substation has a primary voltage in excess of 40 kV and a nameplate capacity in excess of 500 kW. Each entity, of course, funds the cost of its ownership in new generation.

COORDINATION OF OPERATIONS

GPC manages and operates the jointly owned generation and the Integrated Transmission System by contract.

Both Oglethorpe and MEAG are considering data acquisition systems that, in essence, would establish control areas within the Southern Company (Chapter 6) control area, so that real-time monitoring of load-capacity relationships and the administration of service schedules could be effected.

The joint owners agree that the lowest cost to all participants would result from a combined operation in a single control area. However, the establishment of individual subcontrol areas may be necessary so that proper management of resources and administration of service schedules can be accomplished to account properly for the liabilities and benefits of combined operation.

POSITIVE AND NEGATIVE RESULTS OF POOLING ORGANIZATIONS

Inherent in pool operations are advantages in the interrelated objectives of economy, reliability, and adequacy of power supply. The disadvantages of power pooling exist primarily when there is not a fair division of the liabilities and benefits. This statement is basically true for the entry levels of power pooling. As stated elsewhere, the last increment of savings may not justify the cost of sophisticated communication and control networks. Another disadvantage of power pooling is the possibility of the scope of the pool extending beyond the attention span of the pool coordinators so that the true reliability at a given time may not be known, or the last element of coordination for economy may not be achieved.

EVALUATION BY COORDINATING GROUP OF ITS STATUS

Even though MEAG represents roughly 10 percent of the load previously served by GPC, and Oglethorpe represents about 15 percent of the original GPC load, these entities are small in comparison to GPC and even smaller in comparison to the Southern Company. Having been in the roles of customer and supplier for many years, MEAG and Oglethorpe find it difficult to overcome some of the built-in thought processes, and the supplier-customer relationship often predominates in negotiations with GPC. This basic thought process is further exemplified by the original contracts, in which the only recourse for specific performance is the court system. Among participating utilities with common goals, it is much more appropriate to write agreements that set forth basic intent and, in the event of misunderstanding, to submit to arbitration.

If these disadvantages are not eventually overcome, it is quite likely that MEAG will avoid the formation of a Georgia Pool and in its place opt for the formation of a larger Southeast Power Pool to dilute the authority of GPC. As an alternative, MEAG could seek to establish and maintain its rights through interconnection agreements and service schedules, as required by the NRC settlement, and operate without the benefit of a formal pool agreement. In operating without a formal pool agreement, MEAG would look to the Southeastern Electric Reliability Council (SERC) for reliability review of generation and transmission arrangements and the establishment of minimum acceptable reserve levels.

MEAG believes that the operation of a pool as a single control area has reliability and economic advantages in closely knit geographic areas. If the pool has a large number of entities, as Florida does, the last increment of reliability and economy probably will not justify the redundant communications systems necessary to integrate the pool fully, as compared to multiarea coordination by programs like the energy broker system in Florida.

CHAPTER 9
ALABAMA ELECTRIC COOPERATIVE

AREA DESCRIPTION

The Alabama Electric Cooperative (AEC) operates in Alabama and northwest Florida. Figure 16 is a map showing the location of member systems.

AREA CHARACTERISTICS INFLUENCING COORDINATION

As shown in Figure 16, members of the AEC are located within the service area of the Alabama Power Company (APC) and its affiliate the Gulf Power Company (GPC). Historical relationships proved to be a barrier to initiation of any meaningful coordination with APC through 1971.* The situation has improved somewhat. Interconnection agreements are in effect with APC and negotiations are taking place regarding increased coordination. It is too early to report on the likelihood of the success of these discussions.

POWER POOL MEMBERSHIP AND ORGANIZATIONAL STRUCTURE

AEC is a generation and transmission cooperative that operates, for its members, electric generating plants and a transmission system in Alabama and Florida.

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*APC does not agree with AEC's interpretation of history. Since its inception as an operating entity, AEC has had interconnections with APC through which it has achieved coordination, including backup support in the form of a deficiency power supply. Through such backup support, AEC met its capacity reserve and maintenance requirement at an extremely economical price. Such an arrangement was found to be just and reasonable by the FPC in Docket No. E7138; however the FPC did require the FPC staff to conduct joint studies with the parties to determine whether revisions in such an arrangement were required because of new capacity being added by AEC. Such studies, completed in December 1969, led to the new Interconnection Agreement between AEC and APC in early 1972.

AEC rejects as historically inaccurate the footnotes which APC is inserting in this chapter. The great bulk of APC's assertions in these footnotes have long since been rejected by the Nuclear Regulatory Commmission Licensing Board decisions cited later in this chapter.

FIGURE 16--Member Systems of the Alabama Electric Cooperative

At present, AEC furnishes all or a portion of the bulk power supply requirements to its 4 municipal and 2 industrial members and 8 of its 16 cooperative members. Nine of the cooperative members of AEC take all or a portion of their requirements (except for preference power allocations from the Southeastern Power Administration (SEPA)) from the APC. Four distribution cooperative members in northwest Florida take all or a portion of their power requirements (except for a similar SEPA allocation) from the Gulf Power Company. Table 9 lists the AEC membership and data relative to their requirements.

HISTORY OF POWER POOL ORGANIZATION

AEC began to operate its system on September 1, 1944, with the acquisition of the electric system owned by the Alabama Water Service Company. The initial system was largely hydroelectric with peaking capacity; its deficiency power and energy was purchased from APC.

TABLE 9--AEC Members and Their Purchase Requirements (1978)

Member	Requirements (MWh)
City of Andalusia	75,058,000
City of Elba	38,875,200
City of Opp	61,166,400
City of Brundidge	22,348,800
Micolas Cotton Mill	32,563,000
Opp Cotton Mill	29,062,000
Baldwin County EMC	212,679,547
Central Alabama EC	200,694,291
Choctawhatchee EC	150,628,280
Clarke-Washington EMC	143,457,244
Coosa Valley EC	73,437,819
Covington EC	211,548,300
Dixie EC	106,709,676
Gulf Coast EC	78,775,800
Pea River EC	141,397,900
Pioneer EC	92,962,558
South Alabama EC	115,419,700
Southern Pine EC	156,579,100
Tallapoosa River EC	131,598,881
Wiregrass EC	140,703,238
Total	2,215,665,734

In fact, AEC had to rely partially on APC for supplemental bulk power supply for AEC's integrated generation and transmission system until 1978, when AEC placed a 235-MW steam electric generating unit in service and the system became self-sufficient for the first time. Although the situation has improved somewhat, APC has for many years attempted by litigation, refusals to coordinate, and other means, to prevent AEC from developing an adequate bulk power system for its members, preventing or delaying efforts of the cooperative to develop and expand its generation and transmission system. This effort included APC refusals to coordinate with AEC if such coordination would bolster or improve the economy and reliability of AEC's system and allow it to serve additional loads of its members who were purchasing at wholesale from APC.*

This fear of competition from AEC proved to be a barrier to the initiation of any meaningful coordination with the APC through 1971. As a result of a proceeding before the Federal Power Commission involving AEC and the APC, negotiations were started in 1969 concerning the development of

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*See generally, Initial Decisions of the Nuclear Regulatory Commission Licensing Board in Alabama Power Company (Farley Nuclear Plant, Units 1 and 2), Docket Nos. 50-348A and 50-354A, 5 NRC 804 and 5 NRC 1482 (1977), pending on exceptions before the NRC Appeal Board. As the Licensing Board found (5NRC 953-954 and 957) with respect to a number of the major utilities in the Southeast: "The participants intended to engage in various forms of economic coordination among themselves, but through a means which would deter, discourage and even exclude smaller publicly owned utilities, such as municipal distributors, cooperatives, and stateowned entities, with whom they competed from such coordination...The Board finds on this record that Applicant (Alabama Power Company) intended to, and did, take steps to ensure that economic coordination matters were eliminated or separated from reliability considerations in order to avoid strengthening the position of publicly owned utilities such as AEC which competed with Applicant. Applicant's conduct in this regard is anticompetitive and inconsistent with the antitrust laws. Applicant's actions demonstrate a pattern of anticompetitive conduct which occurred throughout the 1960's into the early 1970's toward AEC." In general, these decisions illuminate the APC's historic policies toward AEC.

APC disagrees with this interpretation submitted by AEC. APC did on certain occasions, object to AEC plans to construct small, inefficient generating units utilizing loans with interest rates of 2% from the Rural Electrification Administration for the purpose of displacing central station service then being provided by APC. Such plans were not only wasteful development of uneconomic generation facilities, they also were in derogation of the intent and purpose of the Rural Electrification Act of 1936. It should be noted that such plans promoted by AEC during the period were not for the purpose of achieving coordination, but rather to displace generating facilities developed to meet loads with facilities financed through Government subsidies.

interconnection and coordination arrangements. After approximately 3 years of negotiations--marked by the APC's reluctance to proceed promptly--the parties finally reached an accord and executed a limited interconnection agreement in February 1972.

The main benefit of this agreement to AEC was improved reliability from the addition of interconnection points with the APC. The agreement also provided AEC for the first time with some of the additional coordination benefits from power pooling. These included provisions for emergency services (used by the APC on a number of occasions), maintenance services, and economy energy transactions. However, the reserve obligation in the agreement required that AEC maintain 15 percent (of peak demand) reserves and the backup of its largest unit, which was accomplished by the purchase of "protective capacity" from the APC and standby capacity from SEPA.

In late 1975, AEC began construction of two 235-MW steam electric generating units at its Tombigbee Power Plant. For the first time, APC did not oppose new AEC generation and, in fact, agreed to the joint use of 230-kV transmission facilities to fulfill transmission needs by both AEC and the APC. This joint-use agreement was incorporated into the interconnection agreement.

After negotiations with the APC for ownership participation in the Farley Nuclear Plant failed, AEC was permitted to intervene in the antitrust proceeding on the licensing of this plant by the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission (NRC). (See footnote on page 102.) The hearing by this board started in December 1974 and was concluded in 1977, with the board issuing initial decisions in the two phases of the hearing. In the second phase, intended to adjudicate the appropriate remedy, the board directed APC to offer to sell AEC unit power from the two Farley units and to offer to wheel this power to AEC and to its nonserved members.* Another license condition required the APC to agree to a reserve sharing provision to replace the protective capacity clause in the AEC-APC Interconnection Agreement.** This proceeding is now before the NRC Appeal Board, and all parties are taking exceptions to the ruling of the Atomic Safety and Licensing Board.

In any event, since this decision, APC has been negotiating with AEC on a new reserve requirement. Other revisions to the 1972 interconnection agreement are being negotiated, including a provision for the purchase and sale of electric capacity. Negotiations have also taken place with APC concerning transmission service (wheeling) arrangements. APC expressed no

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*APC offered to negotiate for the sale of unit power from the Farley Plant before the evidentiary hearings began in December 1974. AEC rejected such offer then, as it has done since the order was issued in 1977.

**Since the initial decision, APC has repeatedly offered to eliminate the existing reserve provisions and institute provisions that would conform to the initial decision. AEC rejected such offer; however, subsequent negotiations have resulted in an agreement in principle to a reserve maintenance provision which is more favorable to AEC than that required by the initial decision.

interest in the staggering of generation with AEC in 1975 in connection with AEC's proposed generation, but did indicate an interest in purchasing some excess capacity. Although APC expressed interest in this capacity over several years and testified that it would purchase the capacity during the antitrust proceeding, APC later informed AEC that it was no longer interested in the capacity.* This excess capacity then placed a temporary economic constraint on AEC and required it to seek wheeling arrangements to use this capacity. APC was requested to permit AEC to supply two of its own nonserved members, which were being supplied by APC under wholesale contracts, with APC wheeling this power to these members. APC has agreed to this after the expiration of a 2-year notice required by the wholesale contracts for terminating service. Wheeling negotiations are also underway so that AEC may wheel power to other utilities outside Alabama. Most recently, the APC has expressed a renewed interest in purchasing AEC's excess capacity during the summer of 1979.

It is of prime importance that negotiations with APC for the wheeling of power to and from other utilities be concluded successfully. Because AEC is surrounded by the Southern Company System, it is unable to engage in transactions with other utilities without access to APC transmission.** Access to other systems is acutely important to AEC because of APC's historic policy of reluctant coordination with AEC.

The same concerns over competition have prevented interconnection and coordination arrangements with GPC in the past. However, negotiations are underway with GPC for possible interconnection and service arrangements with respect to AEC's supply of four distribution cooperatives in northwest Florida, but any arrangements with GPC must have the concurrence of APC because of their interconnected operations. In any event, the only outlet that AEC has to other utilities is the operating companies in the Southern electric system.

POWER POOL AGREEMENTS AND CONTRACTS

As stated, the first meaningful interconnection agreement executed by AEC was with APC in February 1972. The main benefit of the agreement was to improve reliability by the addition of interconnection points with the company, but it also included maintenance services and economy exchanges.

In 1975, the interconnection agreement was amended to include a joint-use agreement to accommodate the APC use with AEC of a 230-kV line installation

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*APC expressed an interest in purchasing such capacity at a time when load projections were such that, assuming a reasonable price, such capacity could have been beneficial to APC's customers. When AEC finally indicated, over one year later, its desire to sell such capacity, the price was not attractive and APC's load projections had changed so as to make such a purchase unacceptable.

**APC disputes this statement. AEC is already interconnected with Georgia Power Company and has transmission lines in close proximity to the lines of the Gulf Power Company. It also has transmission lines in close proximity to electric systems in Mississippi.

in connection with AEC construction of two 235-MW steam electric generating units.

Current negotiations with APC involve reserve requirements, provisions for the purchase and sale of electric capacity, and wheeling. An interconnection agreement with GPC is also being negotiated.

RESPONSIBILITIES OF POOLING MEMBERSHIP

AEC now operates for its members electric generating plants and a transmission system in Alabama and northwest Florida and, in general, it serves as the power supply agent for its distribution cooperative members. As a generation and transmission arm of its members, AEC is obligated to furnish directly the needs of its members to the extent that it can physically and economically do so.

POSITIVE AND NEGATIVE RESULTS OF POOLING ORGANIZATIONS

Coordination to date has provided AEC with improved reliability, better economies through the ability to exchange power, joint-use agreements, and increased flexibility of operation through maintenance service.

EVALUATION BY COORDINATING GROUP OF ITS STATUS

AEC believes that APC and GPC already realize most of the benefits of coordination through the Southern Company pool and consider coordinating services with another utility such as AEC to be a marginal gain at most. However, substantial economic gains can accrue to the companies in the future from coordinated transmission planning, such as the 230-kV joint-use agreement with APC. Moreover, all parties would benefit from the staggering of generation and related short-term capacity transactions, especially in view of today's economic conditions and environmental climate. Apparently, the power pooling arrangements and pricing mechanisms in the Southern Company pool agreement, make such coordination difficult.

AEC is certainly in favor of greater coordination with the Southern Company pool and others. Coordination among electric systems can generally reduce the cost of service and improve reliability for a given cost. New generation and transmission facilities should be planned on the basis of combined area requirements; these goals can be accomplished without AEC merging with the Southern Company pool and sacrificing its independence, and without any material disruption of the operation of the Intercompany Interchange Contract (IIC).

CHAPTER 10
TENNESSEE VALLEY AUTHORITY SUBREGION

AREA DESCRIPTION

The Tennessee Valley Authority (TVA) is a corporate agency of the United States created by the Tennessee Valley Authority Act of 1933 (48 Stat. 58, as amended, 16 U.S.C. 831-831dd (1970)). In addition to programs for flood control, navigation, and regional development, TVA operates a power system supplying the power requirements for an area of approximately 80,000 square miles covering practically all of Tennessee; portions of southwestern Kentucky, northern Mississippi, northern Alabama, and Georgia; and small sections of North Carolina and Virginia. (See Figure 17.) This area has a population of about 6.5 million people.

AREA CHARACTERISTICS INFLUENCING COORDINATION

The TVA generating system consists of 29 hydroelectric generating plants, 12 fossil-fueled steam generating plants, one pumped-storage hydroelectric plant, and one nuclear plant licensed to operate. In addition, power from the Army Corps of Engineers' dams in the Cumberland River basin, and dams owned by the Aluminum Company of America on Tennessee River tributaries is made available to TVA under long-term contracts. The TVA bulk power transmission system is shown in Figure 18.

TVA provides electric power to three major groups of customers: municipal electric systems and rural electric cooperatives; directly served industries; and directly served Federal agencies (Figure 19). TVA supplies power to 160 municipal and cooperative electric systems, which in turn distribute power to more than 2.5 million customers. Included in these municipal systems are such cities as Chattanooga, Huntsville, Knoxville, Memphis, Columbia, Nashville, and Tupelo. The Federal agencies served directly by TVA include the Marshall Space Flight Center of NASA at Huntsville, Alabama; the Arnold Engineering Development Center of the Air Force at Tullahoma, Tennessee; and the Department of Energy plants at Oak Ridge, Tennessee, and Paducah, Kentucky.

The region served by TVA is more electricity-intensive than the United States but is probably less end-use energy-intensive in terms of total British thermal units (Btu) of energy consumed per capita. For example, the total energy consumption per capita in Tennessee in 1970 was 271 million Btu compared with the national average of 322 million Btu.

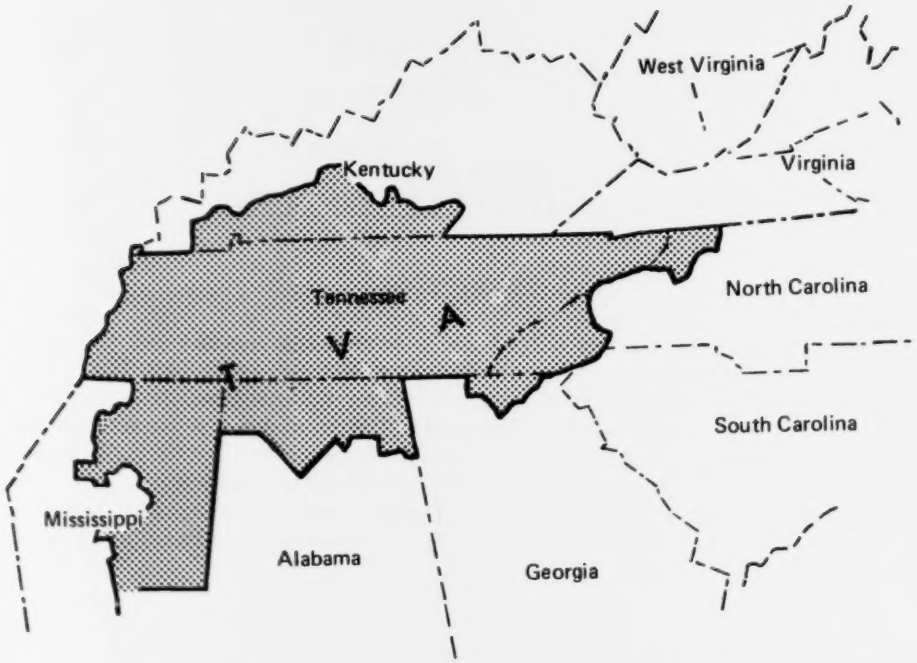


FIGURE 17--TVA Subregion

The TVA peakload in fiscal year 1979 occurred on January 9 at 8 a.m. when a demand of 21,540 MWe was met by the system. At the time of this peakload, TVA had approximately 28,695 MWe of installed generating capacity.

TVA area loads are characterized by a mixture of residential, commercial, small and large industrial, and Federal loads. In fiscal year 1978, the total energy requirements for the TVA system were 123.3 billion kWh.

POWER POOL MEMBERSHIP AND ORGANIZATIONAL STRUCTURE

TVA is not a member of any power pool. However, TVA could be considered a pool in that it has central planning, it is centrally dispatched and controlled, it is operated from five dispatching areas, and it is interconnected at 30 points, 5 of which are at 500 kV, 1 at 345 kV, and 1 at 230 kV.

To provide a reliable supply of bulk power at the lowest possible cost, TVA maintains close coordination in matters of planning and operation with other utilities on the interconnected systems. Because of the large number of interconnecting points, TVA has various types of interchange arrangements with neighboring electric systems. Some of these agreements are diversity exchange, emergency assistance, economy interchange, maintenance energy, short-term power and energy sales, and emergency conservation energy. The

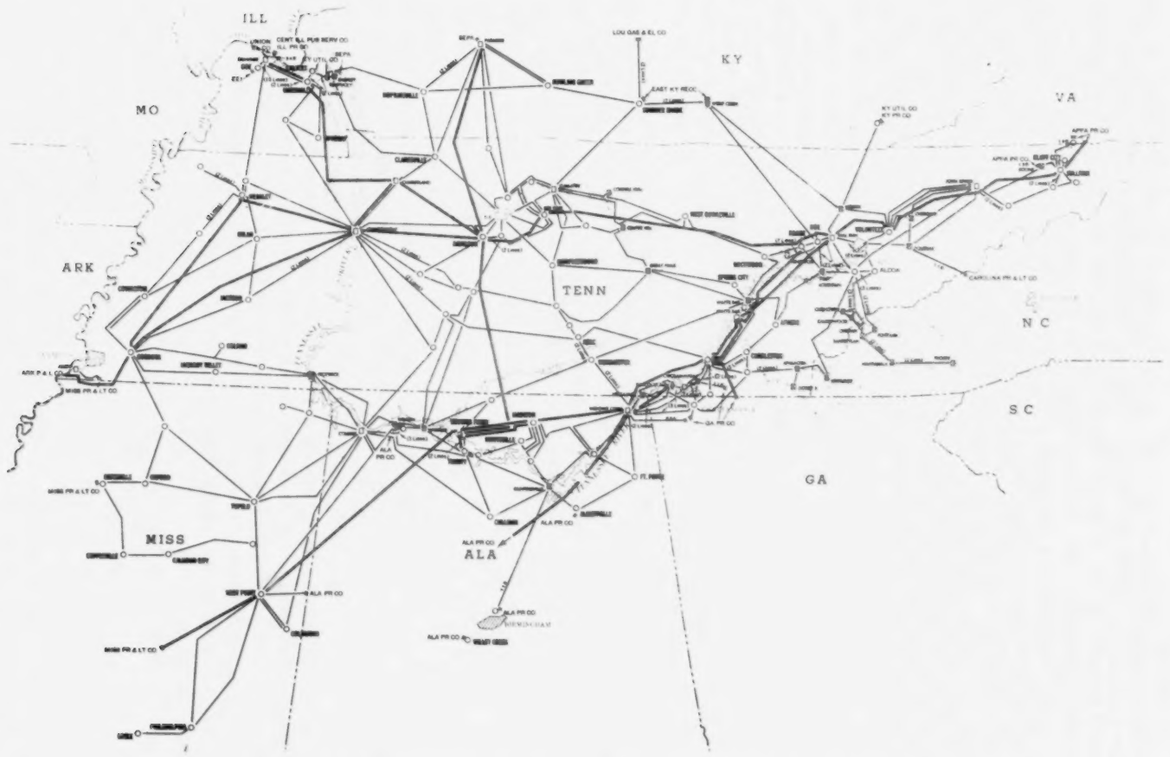


FIGURE 18--TVA Subregion Bulk Power Transmission Network

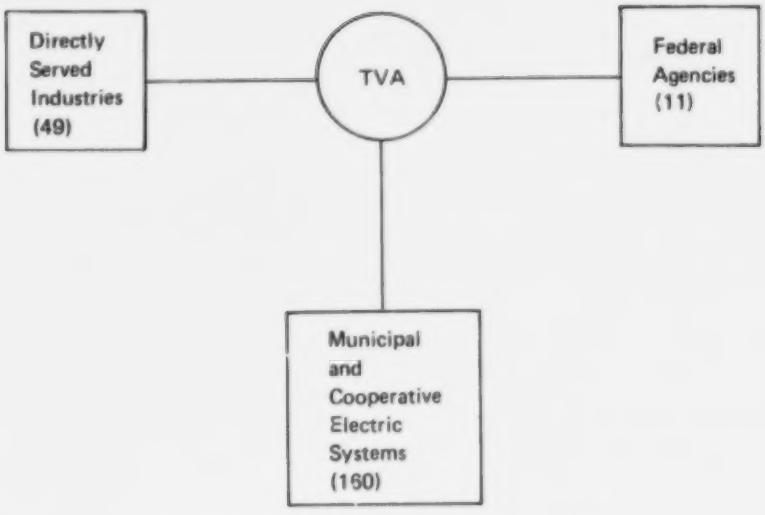


FIGURE 19--Groups Served by TVA

extent and types of transactions depend on the characteristics of the systems' loads, the management policies of the systems, and other factors. Interchange arrangements are an essential part of an electric system's efforts to minimize investment in electrical facilities, increase the reliability of service, effect operating econonies, and minimize the cost of electric energy.

HISTORY OF POOL ORGANIZATION

The concept of power pooling has been reviewed several times. The most recent evaluation of load management, power pooling, and reserve requirements was for the Presidential Initatives in early 1977. However, after considerable discussion and study within TVA and with other contiguous utilities, the conclusions reached in early 1978 were that the activities proposed for power pooling and reserve requirements would provide little or nothing new in pooling techniques; that such systems are already widely used throughout the United States; that the benefits to TVA of high-level computer-computer ties would be minimal; and that the involvement of the TVA system in this proposal would not be in the best interest of its power consumers. For these reasons, the recommendation was that the proposal be dropped.

In 1963 or 1964, TVA conducted a study of benefits of interconnections that culminated in diversity interchange agreements of 1800 MW between TVA-SCEC (South Central Electric Companies) (1500 MWe) and the Southern Company (300 MWe) in 1965, and of 260 MW with the Illinois-Missouri group in 1972, for a total of 2060 MW.

POWER POOLING AGREEMENTS AND CONTRACTS

TVA, a winter-peaking system, has diversity interchange agreements with utility groups whose peaks occur in the summer months. This diversity interchange power of 2060 MWe is considered by TVA to be firm generating capacity during its peak season and is accounted for in that manner in all generation planning studies. Because of changing conditions (e.g., load patterns) on the TVA system, the diversity interchange agreement with SCEC will be reduced to a 1100-MWe exchange level and the agreement with the Southern Company will be reduced to a 220-MWe exchange level at the beginning of the winter exchange period of 1979-80. These changes will reduce the amount of interchange power on the TVA system from 2060 to 1580 MWe. Beginning with the winter exchange period of 1980-81, the diversity interchange with SCEC will be further reduced to 700 MWe and the agreement with the Southern Company will be further reduced to a 140-MWe exchange level, thus reducing the amount of interchange power from 1580 to 1100 MWe.

TVA uses interruptible load under contract as an operating reserve (interruptible on 5-minute notice). Interruptible load is used to peak-shave and to provide operating flexibility by covering contingencies (such as sudden large demand increases resulting from corresponding changes in temperature at the time of the system peak), and for offsetting the effects of loss of spinning reserve as a result of an instantaneous loss of a large unit.

TVA has four basic types of interruptible power under contracts with large industrial customers it serves directly: 2.0-, 2.5-, 3.0-, and 5.0-percent. TVA has the right to curtail power 2.0, 2.5, 3.0, and 5.0 percent of the time during the respective 10-year contract periods. As of September 1, 1979, TVA had under contract 20.0 MWe of 2.0-percent interruptible power, 57.5 MWe of 2.5-percent interruptible power, 270.0 MWe of 3.0-percent interruptible power, and 357.0 MWe of 5.0-percent interruptible power.

TVA has reliability coordination agreements with all of the contiguous utilities. As shown in Figures 20-22, there is a close coordination of planning and operation on a continuing basis within the Southeastern Electric Reliability Council (SERC) and with other reliability councils, such as ECAR and MAIN. TVA has a group that has sole responsibility for conducting joint operational and planning studies on a full-time basis.

TVA is represented on the recently established Reliability Review Subcommittee (RRS) of SERC, whose purpose is to review on a continuous basis reliability matters affecting member systems, with emphasis on coordination of subregional and interregional studies and investigations.

RESPONSIBILITIES OF POOL MEMBERSHIP

COORDINATION OF PLANNING

After the 1965 Northeast blackout, TVA participated in the organization of the national and regional reliability councils that established

FIGURE 20--Planning and Operating Activities of TVA with VACAR, VST, and VAST

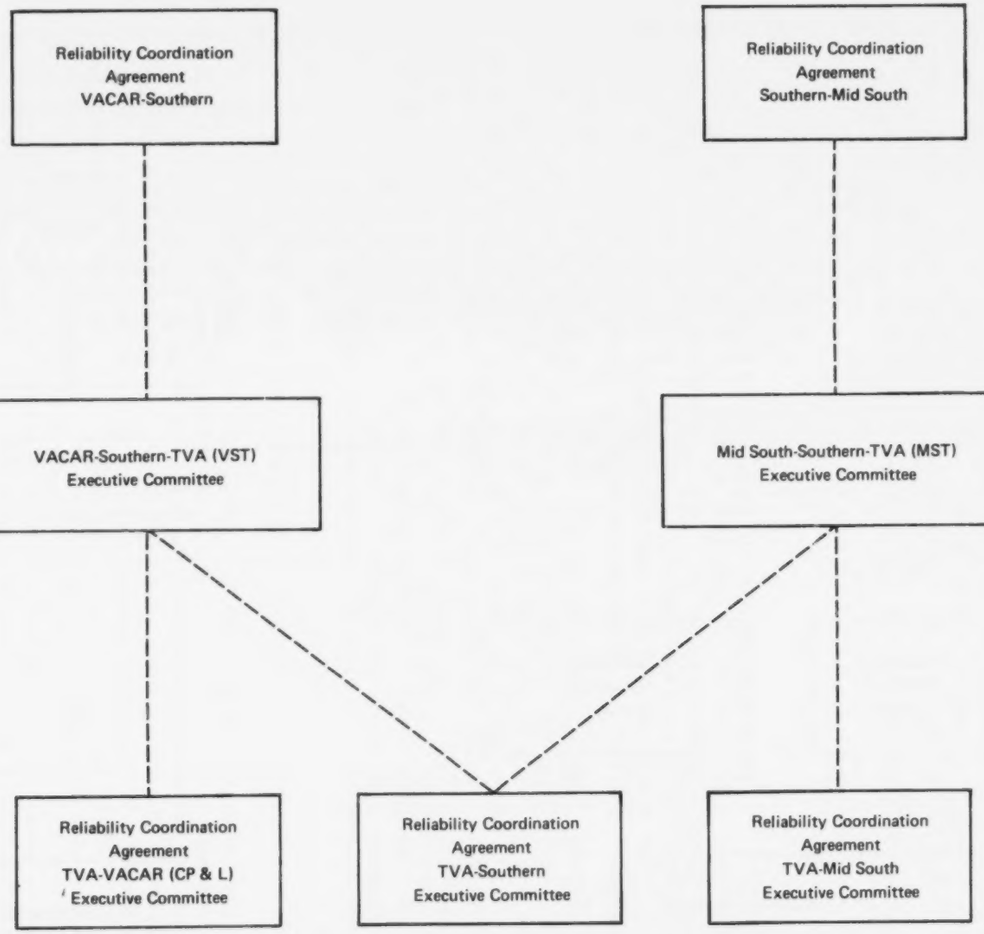
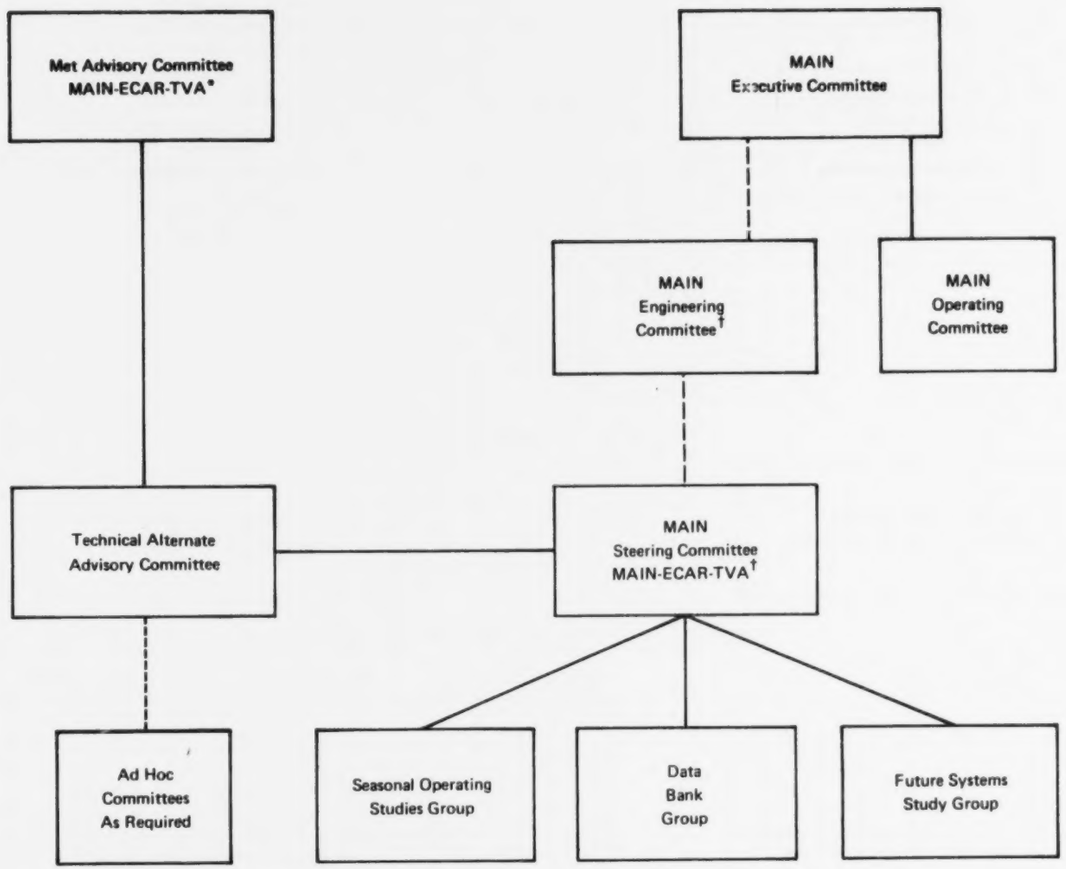

Reliability Coordination Agreement VACAR-Southern
Reliability Coordination Agreement Southern-Mid South
VACAR-Southern-TVA (VST) Executive Committee
Mid South-Southern-TVA (MST) Executive Committee
Reliability Coordination Agreement TVA-VACAR (CP & L) Executive Committee
Reliability Coordination Agreement TVA-Southern Executive Committee
Reliability Coordination Agreement TVA-Mid South Executive Committee

FIGURE 21--Planning and Operating Activities of TVA with VST and MST



*Inter-Regional Agreement among MAIN-ECAR-TVA

† Liaison Representation

FIGURE 22--Planning and Operating Activities of TVA with ECAR and MAIN

reliability criteria and increased coordination of power system planning on a subregional, regional, and national level. TVA is a member of SERC, which was established in January 1970 as one of the nine members of the National Electric Reliability Council (NERC). The purpose of NERC is to encourage improvement in the planning and coordination of bulk electric power systems at the national and regional levels. TVA is also a member of the North American Power System Interconnection Committee (NAPSIC) Southeast Region. NAPSIC plays a key role in setting minimum criteria for operating reliability, control performance, coordination with the reliability councils, and other areas.

COORDINATION OF OPERATION

One example of coordination by NAPSIC is the procedure for a communications network for operational information, which was put into effect in the Southeast Region on March 15, 1979. The Southern Company Power Coordination Center (PCC) was selected as the focal point for the four major subregions (TVA, Southern, Virginia-Carolinas (VACAR), and Peninsular Florida) of the NAPSIC Southeast Region during actual or expected system emergencies.

For economics and reliability, TVA system operators maintain continuous liaison with other utilities regarding availability and price of power. For the longer term (next 12 months or so), operational planning is carried out in operating committees between TVA and other utilities and is not necessarily limited to the SERC region. Short-term (for example, the next day) operational planning as to availability and price is done by telephone. This type of economy exchange is on a split savings basis. At operating time, TVA power coordinators are in hourly contact (or more often if necessary) with other utilities to share economies of production among other utilities at operating time. This transaction is also a split savings type.

POSITIVE AND NEGATIVE RESULTS OF POOLING ORGANIZATION

In the past, diversity interchange for the TVA system represented a substantial capacity savings for the area served by the TVA. Diversity interchange also had a reserve sharing benefit in that the sending system was responsible for the reserves. In these instances, the benefits of diversity interchange surpassed the benefits of power pooling yet preserved the entity of each company. Diversity interchange may not provide these benefits for every power system. Diversity interchange depends on load diversity between systems, the difference between the magnitude of seasonal peaks on individual systems, and the individual systems' maintenance requirements, among other factors. In recent years on the TVA system, there has been a significant decrease in the differences between the winter and summer peakloads due to changing system conditions. Future projections indicate that the majority of the conservation programs are aimed primarily at reducing the winter electrical heating loads. TVA is currently renegotiating its seasonal capacity exchange agreements to provide mutual benefits to all parties concerned.

Tables 10 and 11 show the TVA transactions for fiscal year 1978.

For economy and short-term purchases, the TVA costs shown are estimated costs. Because of the uncertainty of the estimated cost, the estimated savings are "at least type" savings.

Emergency cash purchases have a dollar cost and a reliability benefit, but it is difficult to quantify the dollar benefit of reliability--for example, the savings associated with avoiding a cascading blackout.

Benefits of emergency return-in-kind transactions are similar to emergency cash transactions except that there are no money exchanges.

EVALUATION BY COORDINATING GROUP OF ITS STATUS

TVA took the routes of (1) diversity exchange for capacity benefits, (2) participation in the reliability council to enhance reliability of the interconnected system, (3) participation with NAPSIC in operational coordination on the interconnected system, and (4) interconnections and coordination with other utilities.

From an engineering point of view, the objective of prudent planning is to provide a reliable supply of power at the lowest possible cost with minimum resources and minimum environmental impacts. Power pooling is an alternative that is creditable when it is based on engineering studies, but there are other alternatives, such as diversity interchange, interconnections, and load management. These alternatives are not utopian ends, either singly or collectively, nor are they applicable to every power system.

TABLE 10--TVA Interconnection Transactions for FY 1978 (Purchases)

Type of transaction	Energy (kWh)	Billing (dollars)	Estimated TVA Cost of next increment (dollars)	Benefits (dollars)
Economy A	4,035,559	108,475,855	128,542,227	20,066,372
Economy B	511,207	13,364,716	17,429,281	4,064,565
Nonreplacement	114,347	3,043,216	3,476,812	433,596
Short-term	884,900	25,999,241	29,091,991	3,092,750
Total	5,546,013	150,883,028	178,540,311	27,657,283
Emergency cash	324,064	16,452,255	--	Not quantifiable
Third party	154,752		(See Sales)	
Emergency return-in-kind	150,712	--	--	Not quantifiable
Diversity interchange	2,799,200	--	--	Not quantifiable
Total	8,974,741	--	--	Not quantifiable

TABLE 11--TVA Interconnection Transactions for FY 1978 (Sales)

Type of transaction	Energy (kWh)	Billing (dollars)	Estimated TVA cost (dollars)	Benefits (dollars)
Economy A	9,116	238,410	168,000	70,310
Economy B	9,400	334,000	286,000	48,000
Nonreplacement	342	9,063	8,550	513
Short term	--	--	--	--
Total	18,858	581,473	462,650	118,823
Emergency cash	12,325	546,092	453,743	92,349
Third party	154,752	7,572,319	6,597,784	974,535
Emergency return-in-kind	13,085	--	--	--
Diversity interchange	2,809,942	--	--	--
Total	3,008,962	--	--	--

CHAPTER 11
SOUTHEASTERN POWER ADMINISTRATION

The Southeastern Power Administration (SEPA) was established by the Secretary of the Interior on March 21, 1950, as a bureau of the Department of the Interior. SEPA was delegated authority to carry out the responsibilities of the Secretary under Section 5 of the Flood Control Act of 1944 to market the electric power and energy produced at multipurpose reservoir projects constructed by the Department of the Army, Corps of Engineers, in 10 southeastern States. On October 1, 1977, SEPA was transferred to the new Department of Energy in compliance with the Department of Energy Organization Act of August 4, 1977.

SEPA owns no transmission facilities. Transmission of power is accomplished by contractual agreement through facilities owned and operated by area utilities. All sales of power are at wholesale to approximately 200 customers for redistribution. Accordingly, SEPA does not have utility responsibility for any part of the area load. SEPA has projects and customers in all four subregions of the Southeastern Electric Reliability Council (SERC).

SEPA has 21 projects operating with an installed capacity of 2,712,375 kW and an average annual energy production of 7 billion kWh. The capacity includes 250,000 kW of pump-turbine units. One project, the Richard B. Russell facility, is under construction with a planned installation of 300,000 kW.

CHAPTER 12
PROSPECTS FOR INCREASED POWER POOLING

As the descriptions provided in this report make evident, there has been a pattern of increasing interconnection and coordination between electric utilities in the Southeast for more than 50 years. The growth has not been at a steady rate, but reflects the shifting perceptions of utility managements toward the benefits and costs of more fully coordinated operation and planning with other entities. Some mechanisms for coordination have proved more satisfactory than others and the coordination patterns and mechanisms have changed accordingly.

Entering into a coordination or pooling agreement constitutes a decision by utility management. In making his decision, each chief executive is not only considering the numerical estimates of benefits and costs presented to him, but is also applying his experience and judgement in evaluating the long-term effects on ratepayers, stockholders, regulatory bodies and other groups important to the affairs of the utility. He is also considering a set of uncertainties, such as the future economic picture, energy supply availability and cost, and the possibility that coordination partners may not be able to meet the terms of the agreement. Consequently, it is not reasonable to conclude that a particular form of coordination is clearly desirable for a utility unless all the considerations, unquantifiable as well as quantifiable, are evaluated and balanced as they would be by the chief executive. Evaluations of the prospects for increased power pooling and coordination must give important consideration to the probable attractiveness of such measures.

One of the usual prerequisites for a utility undertaking a coordination action is a finding that its benefits from the action at least equal its costs. It is not sufficient that there is general agreement that certain coordination measures are likely to provide long-term regional benefits to utilities and ratepayers, in the aggregate; each coordination action, i.e., construction of a transmission line, establishment of a centralized dispatch system, joint ownership of a generating unit, or other, must also pass the test of individual economic justification for each utility. In effect, the economic test helps determine the appropriate timing for coordination measures. As conditions change in the area--increased loads, restrictions on energy supply and plant siting, higher facility and financing costs--the economic benefit-cost ratio of various coordination measures will also change, and may result in the adoption of some measures which were formerly judged uneconomic.

It is evident then that the prospects for increased power pooling and coordination have to be examined in terms of different time periods. Something that is a prospect for 1990 may not be a realistic prospect for

1980. A future measure considered to be ultimately desirable may necessarily have to be preceded by other measures. Historically, coordination in the Southeast has developed on this step-by-step basis and the same pattern is expected to continue in further development of voluntary coordination.

The prospects for increased pooling and coordination should be examined first within each subregion of the Southeast and then with respect to coordination between the subregions.

THE SOUTHERN SUBREGION

Holding company ownership and close communication between the managers of the subsidiary utilities have aided the Southern electric system in becoming an effective power pool with computer controlled economic dispatch of generating units, coordination of the construction of generation and transmission facilities, and coordination of individual utility planning to provide close approximation of a single system plan, while recognizing the autonomy of each utility. The established procedures within the system for examination of potential economies will result in specific improvements in the coordination mechanisms, but the overall coordination system has developed over many decades and is probably as close an approach to single-system planning and operation as is possible with the four separate subsidiary utilities operating in separate states, each with its own regulatory authority and each subject to corporate control by its own board of directors.

Consequently, no specific prospects for an increase in the level of coordination within the Southern electric system can be identified at this time, for either the near or more distant future. Although it is probable that changes in coordination practices will be seen as desirable in future years, they will most likely reflect changed circumstances which cannot now be foreseen.

"Within the Southern Subregion, there exist numerous power supply entities in the private, public, and consumer segments of the utility industry, which feel the need for additional benefits of coordinated or pooled power supply planning and operation. For several years, discussions have been held with the objective of forming a Georgia power pool, however, no agreements have been reached in the delineation of principles to cause the equitable sharing of the liabilities and benefits of a power pool. It is anticipated that with further negotiation, acceptable relationships will be established."

THE VIRGINIA-CAROLINAS (VACAR) SUBREGION

Four of the five major utilities in the VACAR Subregion operated for a number of years in the 1960's as a formal contractual power pool under the CARVA agreement. However, all the participating companies found portions of the agreement unworkable as experience was gained in its operation. Today the extensive noncontractual coordination and economy energy transactions now existing in the VACAR arrangement, which includes entities not in the former

CARVA agreement, are accomplishing the economy and efficiency objectives of the former contractual agreement, without the decisionmaking problems. There is some evidence that the smaller utilities believe they were better off under the CARVA agreement, but also recognize that a high degree of both operational and planning coordination is being achieved under the VACAR scheme.

The VACAR utilities recognize that information exchanged between control centers does not assure optimum use of economy energy, and they do not feel that the high cost of a centralized dispatch system would be justified by the small increment of additional benefits that would be realized over the present system.

The appropriate VACAR organizations systematically evaluate the effectiveness of existing contractual agreements and operating procedures. In the past six months, changes in relative fuel costs and the outage of nuclear units have caused the operating task force to make specific changes in the application of economy agreements and to devise a more effective method of marketing energy between the VACAR companies. Planning studies for transmission improvements within the subregion are conducted on a continuing basis and member companies have the responsibility to construct the necessary facilities to maintain adequate transfer capabilities. At this time transmission limitations are not a significant factor affecting transactions between the VACAR companies.

THE FLORIDA SUBREGION

The Florida Coordinating Group is generally considered to be an evolutionary step toward a penisular power pool. With some urging by the Florida Public Service Commission and the Florida Legislature, it has improved economy interchanges through its energy broker system, examined coordinated expansion planning and reserve practices modifications that might reduce costs, regularly surveyed load diversity, and raised the level of information exchange regarding load forecasts and construction plans.

Although the formation of stronger coordination arrangements in Florida is likely to follow the traditional step-by-step process, the generally positive attitude being taken by Florida utilities of all sizes and ownership classes together with the coordination progress already achieved, indicate that further development of pooling and coordination activities within the peninsula can be expected.

Considering the emphasis of the Fuel Use Act on reducing utility oil use, and Florida's present heavy dependence on oil for electric generation, joint ownership of non-oil generation facilities is likely to become one of the major areas of future coordination emphasis.

TENNESSE VALLEY AUTHORITY SUBREGION (TVA)

Because TVA is a centrally managed bulk power supply system that serves the entire area, the issue of improved coordination between separate utilities in the area is largely nonexistent. However, TVA has working

relationships with the Southeast Power Administration and several electric cooperative systems that have importantly aided the operations effectiveness of those systems.

With the efficiencies of central dispatch and centrally managed expansion programs already in hand, TVA has instituted additional measures to encourage energy conservation, including the development of cogeneration within its territory. Although these do not constitute power pooling in the narrow sense, they are examples of coordinated energy actions that can improve the economy of electric supply and result in more efficient use of resources in the TVA subregion. The greatest opportunities for future increases in benefits from TVA coordination appear to lie in arrangements with contiguous utilities.

COORDINATION BETWEEN SUBREGIONS AND WITH OTHER REGIONS

The subregions of the Southeast Region aggregated themselves into the existing groupings for reliability coordination under SERC because of their prior interconnection and coordination experience with each other, which was based on perceptions of mutual advantage and feasibility. Consequently, the groupings for reliability coordination have also been a logical basis for developing further the economic benefits of coordination. Under some conditions benefits can accrue from coordination beyond the limits of a subregion, as evidenced by the diversity exchanges between TVA and the Southern Subregion in the Southeast Region and between TVA and the South Central Electric Companies in the South Central Region.

Generally, there are two basic requirements for effective interchanges between subregions or regions. The first is the existence of interconnections of sufficient strength and the second is the existence of centers of control that can determine the availability of economically advantageous power and energy and that can adjust the operation of the systems as necessary to accomplish the desired power flows. In the Southeast Region, good interconnections exist between the Southern Subregion and the TVA and VACAR Subregions. However, the interconnections between the Florida peninsula and the Southern Subregion have been relatively weak, although they are in the process of being strengthened. There is at present no significant direct interconnection between TVA and VACAR.

Cost considerations aside, Peninsular Florida would gain some reliability benefits from stronger transmission ties to the Southern electric system, but until recently they have not been justifiable. Lower cost coal-generated energy from other areas of the Southeast Region has flowed into Peninsular Florida to replace oil-based generation. Because of the Florida geography, with power flows restricted to the north-south direction and the largest load center at the extreme southern end of the State, the peninsula is more vulnerable than most areas to generation and transmission outages. Additional strong interconnections could provide multiple transmission paths with greater resistance to disturbances and also allow greater emergency support in the case of generation outages. Nevertheless, it is difficult to quantify the benefits of a transmission line which may be used principally in short-duration emergency situations.

The Florida systems would have to construct several hundred miles of additional transmission at considerable expense in order to achieve the most desirable strong interconnection. This lack of benefit-cost justification for additional transmission, on the narrow basis of reliability, has been an impediment to its construction in past years. However, the increasing cost advantage of importing coal-based energy provides an additional quantifiable benefit for stronger interconnections.

Very recent discussions between utilities in Florida and the Georgia Power Company on the possible joint ownership of capacity in Georgia have led to commitments by three utilities to construct a 500-kv interconnection between Georgia and Florida. The first phase would be an extension of 500-kv into north Florida in 1983, followed by a further extension into the central part of east Florida, tying into the 500-kv grid by 1985. Planning for this interconnection is underway.

The task force considered the feasibility and potential benefits of a single power pool encompassing the entire Southeast Region and dismissed it as technically and practically infeasible.

APPENDIX A
COMMENTS FROM INDIVIDUAL TASK FORCE MEMBERS

Each task force member was requested to voluntarily review the comments from invited organizations (Appendix B). They were offered the opportunity to provide their individual comments regarding the responses from the invited organizations and also the final draft of the report.

This section contains the task force members' comments received through July 14, 1980.

FLORIDA MUNICIPAL POWER AGENCY

CALVIN R. HENZE
General Manager

Federal Energy Regulatory Commission
RECEIVED
1980
ATLANTA, GEORGIA

Mr. Aarne O. Kauranen
Federal Energy Regulatory Commission
Regional Office
730 Peachtree St. N.E.
Atlanta, Georgia 30308

Dear Aarne:

I have reviewed the comments of the external reviewers of the Southeast Power Pooling Report and find them very constructive.

The report reflects the viewpoint of all segments of the utility industry in Florida. I enjoyed working on the Task Force.

I have no further comments on the report.

Sincerely yours,

Calvin R. Henze

CRH/ww

cc: Mr. M.F. Hebb, Jr.
Mr. Don Benjamin

Principal Office: Barnett Bank Building, Suite 804/315 South Calhoun Street/P.O. Box 10114/Tallahassee, FL 32302/(904) 224-3314
Operations Office: Orlando Central Park, Suite 148/7200 Lake Ellenor Drive/Orlando, FL 32809/(305) 859-7310

SOUTH CAROLINA ELECTRIC & GAS COMPANY
POST OFFICE BOX 764
COLUMBIA, S. C. 29218

June 26, 1980

Federal Energy Regulatory Commission
RECEIVED
JUN 30 1980
ATLANTA, GEORGIA

Federal Energy Regulatory Commission
Regional Office
730 Peachtree, NE
Atlanta, Georgia 30308

ATTENTION: Mr. Nick Henry

Dear Nick:

I have reviewed the comments provided in response to Mr. Lindsay's letter of April 25. The comments were generally constructive, and only one respondent provided information which requires further qualifier comments.

The American Public Power Association's comments, forwarded by Mr. Herbert Blinder, makes some statements which do not agree with the task force discussions. He states that the VACAR Regional report has a lack of participation by customer-owned systems. It should be pointed out that SEPA was directly represented and that the South Carolina Public Service Authority, a large state-owned utility, was represented within the framework of the VACAR organization. To my knowledge, there are no utilities with significant generation in the Virginia and Carolina areas that are not represented by the VACAR organization.

Mr. Blinder also states that there is minimum pooling among investor-owned utilities in the VACAR area. Apparently, he does not understand the definition of pooling as agreed to by the task force. The report shows there is significant pooling activity in the VACAR subregion and the report outlines this activity in detail.

Please consider these comments in determining what portion of Mr. Blinder's write-up will be included in the final task force report.

Sincerely,

J. H. Young, Jr.
Manager
System Operations and Planning

JHYjr/kmw
cc: Mr. T. C. Nichols, Jr.
Mr. Donald Sterrett, Duke Power Company

DUKE POWER COMPANY
P. O. Box 33189
CHARLOTTE, N. C. 28242

DONALD H. STERRETT
MANAGER, SYSTEM PLANNING

TELEPHONE: AREA 704
373-4404

July 2, 1980

Federal Energy Regulatory Commission
RECEIVED
JUL 9 1980
ATLANTA, GEORGIA

Mr. A. O. Kauranen
Federal Energy Regulatory Commission
Regional Office
730 Peachtree Street, NE
Atlanta, Georgia 30308

Dear Mr. Kauranen:

I have reviewed the comments provided by external reviewers on the draft report of Power Pooling in the Southeast, and offer the following relative to them:

1. In general the comments are perceptive and appropriate, and the criticism I have assumes the reviewer possibly was lacking necessary background information relative to the study.

2. Mr. Jim Young, of South Carolina Electric and Gas Company has pinpointed items to which I would also speak. The comments of Mr. Herbert Blinder of APPA relative to the lack of participation by public bodies indicates that Mr. Blinder is unaware of the composition of the task force itself, or the manner in which the VACAR Subregion is organized. Also, as Mr. Young has pointed out, Mr. Blinder does not appear to be cognizant of the definition of pooling used in the report.

3. Mr. Jerry Pfeffer of DOE has referred to the contrast of the FCG, working within a voluntary framework, and the "apparent failure of the CARVA formal pool agreement". While we concur with Mr. Pfeffer's thought that a formal agreement is not a necessary prerequisite for increased coordination of planning and operations, and certainly the present VACAR Subregion supports that idea, we feel the comparison is hardly valid. The environment in which the CARVA Pool existed bears little relationship to that of the FCG today. In terms of the report, the section on the CARVA Pool should be considered solely in the light of history, and possibly the report places too much emphasis on this specific item.

4. Also, with respect to Mr. Pfeffer's comments, the determination of specific benefits with respect to pooling vs. non-pooling can be a very difficult thing to do. Possibly a strong caveat should be included with Chapter III pointing out that the benefits identified with the pooling are strictly estimates, and that

4. (continued)

within the time allotted for the preparation of the report, it would have been impossible to make any sort of study. FCG had made such a study for their own purposes, and hence had the data available.

Yours very truly,

D. H. Sterrett

DHS:mac

cc: Messrs.: Nick Henry
T. C. Nichols, Jr.
J. H. Young, Jr.

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA
800 Peachtree Center—South Tower, 225 Peachtree Street, Atlanta, Georgia 30303 (404) 659-1555

Federal Energy Regulatory Commission
RECEIVED
JUL 14 1980
ATLANTA, GEORGIA

July 11, 1980

Mr. A. O. Kauranen
Regional Engineer
Federal Energy Regulatory Commission
730 Peachtree Street, N. E.
Atlanta, Georgia 30308

Re: Southeast Region Power Pooling Task Force Report

Dear Aarne:

I have reviewed the comments that various reviewers have provided to Mr. Lindsay, and I have no further comment with regard to the report or their comments.

I recognize that Jerry L. Pfeffer from the Department of Energy had three comments which relate directly to MEAG, however, it is inappropriate to attempt to clarify his concerns in a letter of this nature.

This has been an interesting exercise, however, it is also good to see it get wrapped up. I appreciate the opportunity to participate.

Yours very truly,

Paul

Paul R. Heim
Director, Engineering and Operations

PRH/ijg

meag

TENNESSEE VALLEY AUTHORITY
CHATTANOOGA, TENNESSEE 37401
404 Krystal Building

Mr. Aarne O. Kauranen
Regional Engineer
Federal Energy Regulatory Commission
Regional Office
730 Peachtree Street, NE.
Atlanta, Georgia 30308

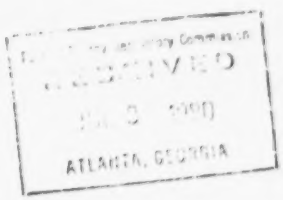
Dear Mr. Kauranen:

I have reviewed the responses provided by the external reviewers of the document on "Power Pooling in the Southeast" and have no comments.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

Ralph J. Thomas, P.E.
Electrical Engineer



An Equal Opportunity Employer

Department of Energy
Southeastern Power Administration
Elberton, Georgia 30635

July 8, 1980

Federal Energy Regulatory Commission
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JUL 9 1980
ATLANTA, GEORGIA

Mr. Aarne O. Kauranen
Regional Engineer
Federal Energy Regulatory Commission
730 Peachtree Street, N. E.
Atlanta, Georgia 30308

Dear Mr. Kauranen:

This will acknowledge receipt of Mr. Wheelock's memorandum forwarding comments from the state commissions and industry agencies on the draft of the Power Pooling report.

We have no comments to submit on the contents included with his memorandum dated June 21, 1980, nor do we have further comments on the draft report itself.

Sincerely,

Elbert M. Rucker
Chief, Division of Power Operations

Florida Power
CORPORATION

M. F. Hebb
Vice President

July 1, 1980

Mr. W. I. Wheelock
Office of Electric Power
Regulation
825 North Capitol Street
Washington, DC 20426

Dear Bill:

I have reviewed the comments of our work "Power Pooling in the Southeast" provided by external reviewers. I accept these as being constructive and as statements of position that the individual Task Force members do not necessarily reflect the views or consensus of others. This was the understanding that I had when I accepted the position as a Task Force member.

The draft of the report properly reflects my personal assessment of the background, current status, and plans in Peninsular Florida for an evolving power pool.

Sincerely,

Maurice

MFH/sk

cc: Mr. D. M. Benjamin, FCG
Mr. E. N. Henery, FERC
Mr. C. R. Henze, FMPA

3201 Thirty-fourth Street South · P. O. Box 14042, St. Petersburg, Florida 33733 · 813-866-4760

Southern Company Services, Inc
Post Office Box 2625
Birmingham, Alabama 35202
Telephone 205 870-6567

Bill M. Guthrie
Executive Vice President

the southern electric system

July 7, 1980

Mr. Aarne O. Kauranen
Regional Engineer
Federal Energy Regulatory Commission
730 Peachtree Street, N. E.
Atlanta, GA 30308

Dear Aarne:

We have reviewed comments by external reviewers on "Power Pooling in the Southeast." We do not believe any of the comments are significant enough to require changing the report. If any changes are to be made other than the corrections supplied with the material, we should have an opportunity to review them and provide comments.

Sincerely,

clw

Federal Energy Regulatory Commission
RECEIVED
JUL 8 1980
ATLANTA, GEORGIA

FLORIDA ELECTRIC POWER COORDINATING GROUP (FCG)
402 REO STREET, SUITE 214 • TAMPA, FLORIDA 33609 • (813) 877-8301

June 27, 1980

Mr. W. I. Wheelock
Office of Electric Power
Regulation
825 North Capitol Street
Washington, D. C. 20426

Dear Bill:

Thank you for the copies of the Comments Provided by External Reviewers of the report "Power Pooling in the Southeast." I have reviewed their suggestions and viewpoints and found them to be quite interesting. There are no comments that I wish to offer on these items.

Sincerely,

Don

DONALD M. BENJAMIN
Acting General Manager

DMB/lg

cc: Mr. M. F. Hebb, Florida Power Corporation
Mr. C. R. Henze, Florida Municipal Power Agency
Mr. E. N. Henery, FERC

APPENDIX B
COMMENTS FROM INVITED ORGANIZATIONS

The following organizations provided comments as requested by the Director, Office of Electric Power Regulation, Federal Energy Regulatory Commission:

- Alabama Public Service Commission
- American Public Power Association
- Electric Utility Systems, Economic Regulatory Administration, Department of Energy
- Edison Electric Institute
- Georgia Public Service Commission
- National Rural Electric Cooperative Association
- Southeastern Electric Reliability Council

The following were also invited to comment:

- Public Utility Commissions from Florida, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia
- NARUC Committee on Electricity
- Office of Power Marketing Coordination, Resource Application, Department of Energy

This section includes comments received from invited organizations through June 20, 1980.

1980 JUN 24 AM 9 27
OFFICE OF
ELECTRIC POWER REGULATION

STATE OF ALABAMA
ALABAMA PUBLIC SERVICE COMMISSION
P O BOX 991
MONTGOMERY, ALABAMA 36130

WILLIAM JAMES SAMFORD, JR.
PRESIDENT

THOMAS R. DEBRAY
EXECUTIVE ASSISTANT

June 19, 1980

Mr. William R. Lindsay, Director
Office of Electric Power Regulation
Federal Energy Reserve Commission
Washington, D. C. 20426

Dear Mr. Lindsay:

In response to your letter of April 25, 1980, inviting my comments regarding the report of the Commission's Southeast Region Task Force, I have reviewed the report with particular emphasis on the Southern Subregion as covered in Chapter 6. The jurisdictional limits of the Alabama Public Service Commission are confined to one operating subsidiary of the Southern Electric Systems, i.e., Alabama Power Company. The Southern Electric System has, in my staff's opinion, developed a model pool within its system and is to be commended for the optimum distribution of the production capacities of its facilities between its subsidiaries and cooperating cooperative and municipal systems. The staff's report to me describes the draft as factually and adequately covering the pooling arrangement in our area and should be compiled into the final report.

Sincerely,

William James Samford, Jr.
President

WJSjr/cm

AMERICAN PUBLIC POWER ASSOCIATION

2600 VIRGINIA AVENUE NW WASHINGTON DC 20037 · 202/342-7200

June 20, 1980

President EARL F. BRUSH
President elect WILLIAM H. CORKRAN, JR.
Vice President JAMES E. BAKER
Treasurer WALTER R. WOMACK
General Counsel NORTHCUTT ELY
Executive Director ALEX RADIN

JAMES E. BAKER
Shrewsbury, Massachusetts
HENRY A. BELL
Columbus, Ohio
EARL F. BRUSH
Lansing, Michigan
WALTER A. CAMMEY
Lincoln, Nebraska
HENRY T. CARLISLE, JR.
Bowling Green, Kentucky
BILL D. CARNAHAN
Lamar, Colorado
WILLIAM H. CORKRAN, JR.
Easton, Maryland
RUSSELL DAU
Missouri Basin Municipal Power Agency
Sioux Falls, South Dakota
NORMAN E. DIETRICH
Austin, Minnesota
JOE B. DYKES, JR.
Tallahassee, Florida
LOMA W. HARTKE
Huntingburg, Indiana
PAUL P. HUGHES
Nashville, Tennessee
PATRICK J. HESTER
Roseville Centro, New York
J. DON HOWLAND
Duncan, Oklahoma
GORDON W. HOYT
Anaheim, California
BEN HUFFSTODT
Princeton, Illinois
JACK H. MADISON
Tillamook People's Utility District
Tillamook, Oregon
RICHARD E. MALOH
Columbia, Missouri
ROBERT L. McKINNEY
Cowlitz County Public Utility District
Longview, Washington
JOHN S. McQUEEN
Chattanooga, Tennessee
JOHN P. MURPHELLY
Omaha Public Power District
Omaha, Nebraska
ROBERT MURRAY
Seattle, Washington
HAROLD G. PAYNE
North Attleborough, Massachusetts
A. J. PRISTER
Salt River Project
Phoenix, Arizona
JAMES H. PHILLIPS
Sebring, Florida
BRUCE PRENTICE
Toronto, Ontario, Canada
HAROLD SCHIESSOUT
Sioux Center, Iowa
SIMON C. SITTERSON
Kinston, North Carolina
J. K. SPRUCE
San Antonio, Texas
WILLIAM P. STROM
Traverse City, Michigan
LOUIS STROUP, JR.
Kansas Municipal Utilities
McPherson, Kansas
GEORGE H. USRY
Athens, Tennessee
LOUIS H. WINNARD
Los Angeles, California
WALTER R. WOMACK
Chelan County Public Utility District
Wenatchee, Washington
ROBERT C. YOUNG
Burlington, Vermont

Mr. William Lindsay
Director
Office of Electric Power Regulation
Federal Energy Regulatory Commission
825 N. Capitol St., N.E.
Mail Station 300-R-B
Washington, D.C. 20426

Dear Mr. Lindsay:

The draft report on Power Pooling in the Southeast prepared by the regional task force is an interesting document. It provides an illuminating look at pooling in the region from the point of view of various participants in the area. It is perfectly acceptable so long as the FERC staff, in drafting the Commission's report, recognizes that the viewpoints expressed reflect institutional attitudes and should not be regarded as an unbiased document.

The report is most useful where it reflects the viewpoint of all segments of the utility industry in a particular area. The sections dealing with Florida, Georgia, and TVA are the most complete from that standpoint.

It is unfortunate that the document lacks the input from certain segments of the municipal and local publicly owned utilities in a number of states, particularly Alabama, the Carolinas, and Virginia. The inclusion of comment from informed people representing municipal utilities in these states would have added to the overall historical review of the pooling in the region and its prospects for the future.

Mr. H. Sewell St. John, Sr., the secretary-treasurer of the Municipal Electric Utility Association of Alabama, can provide information on the viewpoint of municipal utilities in that state. It would provide another perspective to complete the material furnished by Alabama Power Co. and the Alabama Electric Cooperative.

An attempt should be made to supplement the material on the VACAR subregion. As it stands, it is essentially a somewhat defensive story of the minimal pooling among the investor owned utilities of the area. The lack of

any evident participation by consumer owned systems is notable by its omission from the draft. This is especially startling considering the recent formation of large joint action agencies in this subregion and probably means that the interests of a significant sector of the generating entities in the region was not recognized by the VACAR operating agreements.

Mr. Ralph W. Shaw, the general manager of the North Carolina Power Agencies 1, 2 and 3 is probably in the best position to provide the missing viewpoint of the new municipal joint action agencies.

As indicated by our comments APPA strongly agrees with the cautionary note in the Foreward of the report, "To some degree members reflected the views of their own industry segment, ..." The staff in writing its own draft for the Commission should attempt to supplement the task force work by obtaining views that have been omitted.

Sincerely,

Herbert Blinder
Director of Technical Services

HB:vm

cc: Bill Wheelock
Bernard Chew

RECEIVED
1980 MAY 27 PM 4: 29
OFFICE OF
ELECTRIC POWER REGULATION

Department of Energy
Washington, D.C. 20461

May 20, 1980

Dr. William W. Lindsay
Director, Office of Electric
Power Regulation
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Dr. Lindsay:

The draft report on Power Pooling in the Southeast has been reviewed by the Office of Utility Systems' staff. This review was done within the stated framework of the report's objective. The report is understood to focus on the state of pooling in the Southeast Reliability Council (SERC) from a historical and current perspective.

The candor with which various conflicts between systems are discussed is commendable. It is a significant implication of this report that, while there have been continual differences among the systems, there also seems to be a desire to realize the benefits of increased coordination.

The definition stated in the report of a power pool as not only encompassing centralized planning and operations but, also, coordination of planning and operating decisions developed on an independent basis is important and significant. Yet many of the negative statements in the report relative to pooling seem to be based on a perception of pooling only encompassing centralized planning and operations.

The report presents an interesting contrast between the success of the Florida Electric Power Coordinating Group (FCG) working within a voluntary framework as compared to the apparent failure of the CARVA formal pool agreement. The FCG experience would seem to indicate that a formal pool agreement is not a necessary prerequisite for significantly increasing coordination of planning and operations.

The report can be strengthened if the following items are addressed:

- Various estimates are presented of the savings which the SERC subregions have achieved through coordination. It is not clear in all cases whether these savings were achieved among members of a subregion or whether they also include transactions with utilities outside the subregion. It is also not clear whether these were economy energy or capacity transactions or both.

- The report describes the peninsular generation study, the one-hour test to determine the potential for economy interchange, and the central dispatch study, all conducted by the FCG. It is not clear that other groups of utilities have undertaken similar analyses to support their statements that current operating and planning practices offer little opportunity for additional savings through increased coordination.

- VACAR notes, on page 50*, that some operating procedures and interchange agreement changes have recently resulted in improved operations It would help if these changes could be described.

- The second bullet on page 27 beginning with "One power system...." is not clear.

- The paragraph on page 37 in which the roles of federal agencies are described should be expanded to note ERA's authority under Section 202(a) of the Federal Power Act to encourage, on a voluntary basis, increased system coordination and interconnection.

- It is noted on page 94 that several public and consumer-owned utilities, which are part owners in the Integrated Transmission System, are not allowed by Georgia Power Company to take part in planning studies of proposed interties to South Carolina and to Florida. Why are these part owners excluded from such studies?

- There should be some clarification of the discussion on page 95 of the possibility that Oglethorpe Power Corporation and the Municipal Electric Authority of Georgia may establish a control area within the Southern Company control area.

*The page numbers cited in this letter are now 52, 29, 39, 95, and 96 respectively.

The report is very informative and will serve as a useful reference. It would benefit, however, by additional editing to eliminate or minimize the number of judgmental statements that are not supported either by experience or reason.

The Office of Utility Systems appreciates the opportunity to offer these comments.

Sincerely,

Jerry L. Pfeffer
Assistant Administrator
for Utility Systems
Economic Regulatory Administration

JOHN J. KEARNEY, Senior Vice President

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
Washington, D.C. 20036
Tel. (202) 828-7400

May 21, 1980

Mr. William W. Lindsay
Director, Office of Electric
Power Regulation
Federal Energy Regulatory Commission
Washington, DC 20426

Dear Mr. Lindsay:

The Edison Electric Institute appreciates the opportunity to comment on the draft report on Power Pooling in the Southeast.

Overall, we believe that the report provides a reasonably complete and accurate description of regional coordination and power pooling in the Southeast region. However, amplifying on the last sentence on Page 9, we would note that information and views provided by the task force members do not necessarily represent those of all U.S. Electric utilities or even all electric utilities in the Southeast region. The report correctly recognizes the diversity of electric utility systems in terms of financial, geographic and regulatory factors and points out that the Southeast subregions have developed particular coordination arrangements which uniquely apply to each subregion and provide significant benefits to the total Southeast region. The same sort of diversity applies to the total U.S. electric utility industry and the coordination arrangements used in the Southeast region would not necessarily be appropriate in other regions or maximize the benefits attainable in other regions.

The report indicates that significant additional benefits from increased coordination may be realized in the next two decades. We believe this would be possible but we would add that increased coordination should only be pursued if the benefits are justified in terms of associated increased problems and costs to utilities. In the final analysis, we believe that increased coordination is desirable as long as it results in optimizing the cost and reliability of service from the viewpoint of the consumer.

Service reliability and cost efficiency have been recognized objectives of electric utilities since the middle 1930's. During the last forty years, the Southeast region has accomplished a very high degree of coordination in its approach to power system planning and operations. Although it is extremely difficult to quantify the several benefits derived from pooling or other coordination arrangements, it is evident that the Southeast region has sought to take full advantage of opportunities for increasing reliability and optimizing efficiency in the use of facilities. Conservation opportunities have been pursued since the 1970's when national objectives and priorities caused increased emphasis on conservation. Of course, trade offs may be involved between energy conservation, cost efficiency and service reliability.

We note that your cover letter points out that the task forces were not asked to provide explicit findings or recommendations. This is an important caveat, because all of the electric utilities in the region have not had the opportunity to comment at this point in time. The report records differences of view which exist between task force members. The report could not be considered to represent a completely balanced or rounded picture without also recording the differences perceived by all of the utilities identified in the report.

We hope that these comments will be useful to you and to the task force. If the Edison Electric Institute can be of further assistance, please contact me or Fred Denny, our Director of Engineering, who was involved in reviewing the report and preparing our comments.

Sincerely yours,

John J. Kearney

amm

RECEIVED
1980 JUN -9 PM 2:16
OFFICE OF
ELECTRIC POWER REGULATION

COMMISSIONERS:
ROBERT C. (BOBBY) PAFFORD, CHAIRMAN
WILLIAM H. KIMBROUGH, VICE CHAIRMAN
MAC BARBER
BILLY LOVETT
FORD B. SPINKS

HUGH S. JORDAN, SECRETARY

Georgia Public Service Commission
244 WASHINGTON STREET, S. W.
ATLANTA, GEORGIA 30334

June 6, 1980

Mr. William W. Lindsay
Director,
Office of Electric Power Regulation
Federal Energy Regulatory Commission
Washington,D.C. 20426

Dear Mr. Lindsay:

Speaking from the Georgia Public Service Commission point of view, we believe the report on "Power Pooling in the Southeast" accurately reflects conditions in the Southeast.

Our very minor comments are related to a misstatement on page 21 which indicates that MEAG has entered into joint operation with subsidiaries of the Southern Electric System. MEAG has a relationship to only one subsidiary of the Southern Electric System, Georgia Power Company.

A second misstatement is found on page 24. The statement reads in the Cost Savings section that the Southern Electric System estimates an annual capital cost savings of $8.3 million because of its seasonal exchange with TVA. The word, capital, should be eliminated.

Sincerely yours,

Hugh S. Jordan
Executive Secretary

RECEIVED
JUN 11 1980
DIV. OF ISA

Logged letter No. 906

NRECA NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
1800 Massachusetts Avenue, N.W.
Washington, D.C. 20036/202-857-9500

May 13, 1980

Mr. William W. Lindsay
Director, Office of Electric
Power Regulation
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Mr. Lindsay:

This will acknowledge receipt of your letter of April 25 and the enclosed report "Power Pooling in the Southeast" which was prepared by the Southeast Regional Task Force.

Inasmuch as NRECA had one or more representatives participating in the preparation of this report, we plan to withhold our comments until we are asked to review the combined report of all the regions which is to be prepared by the Commission.

We thank you for sending this material to us which we will use as backup material when we review the Commission's drafted report.

Sincerely,

Robert D. Partridge
Executive Vice President
and General Manager

RDP/ajl/MDD

1980 MAY 27 PM 4: 30

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

ELECTRIC POWER REGULATION

W. L. Proffitt
Chairman
Senior Vice President - Power Operations
Virginia Electric and Power Company
P. O. Box 26666
Richmond, Virginia 23261

E. L. Addison
Vice Chairman
President
Gulf Power Company
P. O. Box 1151
Pensacola, Florida 32520

Wm. R. Brownlee
Administrative Manager
308 Daniel Building
15 South 20th Street
Birmingham, Alabama 35233
Phone (205) 252-0069

May 23, 1980

Mr. W. W. Lindsay, Director
Office of Electric Power Regulation
Federal Energy Regulatory Commission
Room 5100
825 North Capitol Street
Washington, D.C. 20426

Dear Mr. Lindsay:

POWER POOLING IN THE SOUTHEAST
DRAFT OF APRIL, 1980
COMMENTS BY VACAR SUBREGION - MR. L. W. EURY

Confirming our telephone conversation, there is attached a copy of comments on the above subject from Mr. L. W. Eury on behalf of the VACAR Subregion of SERC. I tried to telecopy this page to you today, but the operator reported that parts for the machine would be available Tuesday. We understand these comments are acceptable if mailed today or Tuesday.

The Florida Subregion of SERC has been delayed in getting their comments to you, and we hope you will be able to give them consideration. The other two Subregions have only complimentary comments.

I have a couple of editorial comments which should be brought to your attention. On Page 4, Paragraph 5, Lines 5 and 6, Southern Company Services, Inc. is described as "a nonoperating service company subsidiary". Actually, the operating engineering pooling arrangements and minute-by-minute operation are done by the service company for the entire Southern Electric system. Perhaps it would be sufficient to strike the word "nonoperating".

In the same paragraph, beginning with Line 9, there is a list of utilities from which the Crisp County Power Commission of Cordele, Georgia, has been omitted. Its generating capacity is greater than 25 MW.

Sincerely,

Wm. R Brownlee

Wm. R. Brownlee

WRB/llh

Attachment

cc w/attachment:
SERC Executive Committee
SERC-TAC Executive Committee
Mr. E. L. Bivans, Chairman FCG-TAG
Mr. D. M. Benjamin

POWER POOLING IN THE SOUTHEAST
DRAFT OF APRIL, 1980
COMMENTS BY VACAR SUBREGION - MR. L. W. EURY

1. On Page 6 the report states, "It is possible that Florida and VACAR will evolve into an operating mode where each has its own central dispatching".

   VACAR is currently composed of a well-coordinated subregional group of independently dispatched bulk power supply systems. This mode of operation has functioned quite well; and while no formal central dispatching arrangement exists, many of the benefits of such an arrangement are realized. For example, communications among dispatching personnel from each system are implemented on almost a continuous basis, allowing the interchange of electric energy to be realized and making the most effective use of VACAR resources while preserving valuable supplies of oil. In addition, the chief dispatchers from the VACAR systems participate in a conference telephone call each afternoon to discuss the anticipated system operating conditions for the following day and to plan the necessary interchange transactions that will help to minimize oil-fired generation.

2. VACAR operating personnel have recently implemented the practice of reporting to all Member Systems by teletype each hour the available surplus steam capacity and the displaceable oil-fired generation within the Subregion. This measure has been taken to further enhance the possibility of conserving supplies of oil and displacing higher costs of generation.

LWE:WRB/11h
May 23, 1980

APPENDIX C
ELECTRIC POWER CHARACTERISTICS
SOUTHEAST REGION

Florida Subregion
Generating Investor-Owned Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Florida Power Corporation	FLPC	5,028.6	3,899.0	GEPC, TAEC, FLPL, GUPC, SEPA, ORLA TALL, GAMW, KISS LALW, SEBU	
Florida Power & Light Company	FLPL	10,644	8,606	FLPC, JACO, TAEC ORLA, VEBM, NESB FTPA, LAWU, HOME	
Florida Public Utility Company (Fernandina Beach, Florida Division)	FPUC	2.0	36.0		JACO
Reedy Creek Utility Company, Inc.	RCUC	15.0			FLPC
Tampa Electric Company	TAEC	2,457	1,784	FLPC, FLPL, LALW	

Florida Subregion
Generating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Fort Pierce Utility Authority	FTPA	129.7	83.0	FLPL	VEBM, FLPL
Gainesville/Alachua County Regional Utilities Board	GAMW	247.2	162.7		FLPL, FLPC, ORLA
Homestead Munic. Elec. Dept.	HOME	53.1	43.9		FLPL
Jacksonville Electric Authority	JACO	2,163.2	1,226.0	FLPL	FLPL
Key West Utility Board	KEWU	110.3	62.0	US Naval Air Sta.	
City of Kissimmee	KISS	25.9	46.1		FLPC
Lakeland Dept. of Elec. & Water Utilities	LALW	384.2	274.0		TAEC, FLPC, ORLA, TALL
Lake Worth Utility Authority	LAWU	114.9	68.6		FLPL
New Smyrna Beach Utility Commission	NESB	18.2	28.6		FLPL
Orlando Utility Commission	ORLA	724.2	489	FLPC, FLPC	FLPL, FLPC, LALW TALL
St. Cloud Electric & Water Dept.	SCLW	27.0	26.8		ORLA, KISS
Sebring Utilities Commission	SEBU	27.6	30.0		FLPC, ORLA
Starke Light & Water Plant	STFM	9.8	9.1		FLPL
Tallahassee Elec. Dept.	TALL	268.3	203.3	FLPC	FLPC
Vero Beach Munic. Utilities	VEBM	130.4	86.8		FLPC
Wauchula Munic. Light & Water Dept.	WALW	7.6	7.9		FLPC

Florida Subregion
Nongenerating Muncipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Alachua Electric Dept.					FLPC
Bartow City Electric Dept.					FLPC
Bushnell Utility Dept.					FLPC
Chattahoochee Light System					FLPC
Clewiston Electric & Water System					GLDE
Fort Meade Electric Dept.					FLPC
Green Cover Spring Electric Dept.					JACD
Havana Power and Light					TACI
Jacksonville Beach Electric Dept.					JACO
Lake Helen Munic. Electric Light Plant					FLPC
Leesburg Munic. Electric Dept.		6.8[3]			FLPC
Moore Haven Munic. Water & Light Dept.					GLDE
Mount Dora Municipal Electric Dept.					FLPC
Newberry Board of Public Works					FLPC
Ocala Electric Utility		11.4[3]			FLPC
Quincy Munic. Electric Dept.					SEPS, FLPC
Williston Munic. Electric Light Dept.					FLPC

Florida Subregion
Generating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Florida Keys Coop. Assn. Inc	FLKE	16.0	25.7		SIME, SEPA, FLPC
					FLPL
Seminole Electric Cooperative	SIME	140[3]			FLPC
					FLPL

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Florida Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Central Florida Electric Coop. Inc.					SIME, SEPA, FLPC
Clay Electric Cooperative Inc.					FLPL, SIME CAMW FLPC
Glades Electric Cooperative					FLPL, SIME
Lee County Electric Cooperative					SIME, FLPC, FLPL
Okefenoke Rural Electric Corp.					SIME, OEMC, FLPL SEPA
Peace River Electric Cooperative					FLPC. FLPL, TAEC,
Sumter Electric Cooperative					SIME, FLPC
Suwannee Valley Electric Cooperative					FLPL, SEPA. SIME FLPC
Talquin Electric Cooperative Inc.					SEPA, SIME, FLPC
Tri-Country Electric Cooperative					SEPA, SIME, FLPC
Withlacoochee River Electric Coop. Inc.					FLPC, SIME

Florida Subregion
Generating--Other

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Southeastern Power Administration (Jim Woodruff Dam)	SEPA	30.0		FLPC	

[1]Installed capacity and peakload values are from the 1978-79 "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

[2]Abbreviations are from "Plant and Ownership List - 1978," Department of Energy, DOE/E.A - 0057.

[3]Figures represent the amount of joint ownership in the Crystal River Generating Plant.

NOTE: The major interconnections and power suppliers that are shown are from the "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

Southern Subregion
Generating Investor-Owned Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Alabama Power Co.	ALAP	6,535.8	595.2	ALEC, GEPC, GUPC, MIPR, SEPA, SOEG, TEVA	
Florida Public Util. (West Area)	FPUC	0.2			GUPC
Georgia Power Co.	GEPC	10,452.8	9,631.4	ALAP, DUPC, FLPC, SEPA, SAEP, SOCG, SOEG, TEVA	
Gulf Power Co.	GUPC	1,469.2	1,180.0	ALAP, FLPC, GEPC	
Mississippi Power Co.	MIPR	1,965.8	1,218.0	ALAP, GUPC, LOPL, MIPO	
Savannah Electric & Power Co.	SAEP	479.1	463.8	GEPC	
Southern Electric Generating Co.	SOEG	1,019.7	4	ALAP, GEPC	

Southern Subregion
Generating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Crisp County Power Comm.	CCPC	30.5	40.1		MEAG
Municipal Electric Auth. of GA	MEGA	220.6	3		GEPC, SEPA

Southern Subregion
Nongenerating Municipal System

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Acworth Water & Light Comm.					GEPC
Adel Light Dept.					MEAG
Albany Water, Gas, & Light Comm.					MEAG
Alexander City Electric Dept.					ALAP, SEPA
Andalusia Electric Dept.					ALEC
Barnesville Electric Dept.					MEAG
Blakely Light & Water Dept.					MEAG
Blounstown Munic. Elec. Dept.					FPUC
Brinson					MEAG
Brundidge Electric Distr. System					ALEC
Buford Municipal Light System					MEAG
Cairo Light & Water Dept.					MEAG
Calhoun Light Dept.					MEAG
Camilla Water & Light Dept.					MEAG
Cartersville Electric System					MEAG
College Park Electric System					MEAG
Collins Munic. Light & Power Plant					SOPE
Commerce Water & Light Comm.					MEAG
Covington Municipal Utility Dept.					MEAG
Dalton Water & Light Comm.		3		MEAG, SEPA	
Doerun Water & Light Dept.					MEAG
Dothan Electric Dept.					ALAP
Douglas Light & Water Dept.					MEAG

Southern Subregion
Nongenerating Municipal System

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
East Point Electric Dept.					MEAG
Elba Water & Electric Bd.					ALEC
Elberton Water & Light Dept.					MEAG
Ellaville Munic. Light Plant					MEAG
Evergreen Munic. Light Dept.					ALAP
Fairburn Light & Water Plant					MEAG
Fairhope Electric Dept.					ALAP, SEPA
Fitzgerald Water, Light, & Bond Comm.					MEAG
Riviera Utilities (Foley Util. Bd.)					ALAP, SEPA
Forsyth Water & Light Dept.					MEAG
Fort Valley Utilities Comm.					MEAG
Grantville Water & Light Comm.					MEAG
Griffin Electric Dept.					MEAG
Hampton Electric Dept.					GEPC
Hartford Water & Light Dept.					ALAP, SEPA
Hogansville Munic. Lt. Plant					MEAG
Jackson Electric Dept.					MEAG
Lafayette Munic. Light Dept.					ALAP
La Fayette Munic. Elec. Dept.					MEAG
LaGrange Electric Dept.					MEAG
Lanett Electric Dept.					ALAP, SEPA
Lawrenceville Electric Dept.					MEAG
Luverne Light Dept.					ALAP, SEPA

Southern Subregion
Nongenerating Municipal System

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Mansfield Electric Dept.					MEAG
Marietta Bd. of Lts. & Water Wks.					MEAG
Monroe Water, Light & Gas Comm.					MEAG
Monticello Electric Dept.					MEAG
Moultrie Water & Light Dept.					MEAG
Newnan Water & Light Comm.					MEAG
Opelika Light & Power Dept.					ALAP
Opp Utilities Dept.					ALAP
Oxford Water & Light Dept.					GEPC
Palmetto Light & Water Dept.					MEAG
Piedmont Electric Dept.					ALAP
Robertsdale Munic. Elec. Dept.					ALAP
Sandersville Water & Lt. Comm.					MEAG
Sylacauga Utilities Bd.					ALAP, SEPA
Sylvania Munic. Electric Dept.					MEAG
Sylvester Munic. Lt. & Water Plt.					MEAG
Thomaston Electric Dept.					MEAG
Thomasville Water & Lt. Dept.					MEAG
Troy Electric System					ALAP
Tuskegee Light Dept.					ALAP, SEPA
Washington Electric Dept.					MEAG
West Point Lt. & Water Dept.					MEAG
Whigham Electric Dept.					MEAG

Southern Subregion
Generating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Alabama Electric Coop., Inc.	ALEC	141.1	243.0	ALAP, SEPA	ALAP, SEPA
Oglethorpe Elec. Memb. Corp.	OEMC	503.0[3]	135.0		GAPC
South Mississippi EPA	SOMI	621.6	272.0		MIPS, SEPA

Southern Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Altamaha Elec. Memb. Corp.					OEMC
Amicalola Elec. Memb. Corp.					OEMC
Baldwin County EMC					ALAP, ALEC
Black Warrior EMC					ALAP, SEPA
Canoochee Elec. Memb. Corp.					OEMC
Carroll Elec. Memb. Corp.					OEMC
Central Alabama EC					ALAP, SEPA
Central Georgia Elec. Memb. Corp.					OEMC
Choctawatchee EC, Inc.					ALEC
Clarke-Washington EMC					ALEC
Coastal Elec. Memb. Corp.					OEMC
Coast EPA					MIPR, SEPA
Cobb Elec. Memb. Corp.					OEMC
Colquitt Elec. Memb. Corp.					OEMC
Coosa Valley EC, Inc.					ALEC
Covington EC, Inc.					ALEC
Coweta-Fayette Elec. Memb. Corp.					OEMC
Dixie EC					ALAP, SEPA
Dixie EPA					SOMI
Douglas Cty. Elec. Memb. Corp.					OEMC
East Mississippi EPA					MIPR, TEVA
Escambia River EC, Inc.					GUPC, SEPA
Excelsior Elec. Memb. Corp.					OEMC

Southern Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Flint Elec. Memb. Corp.					OEMC
Grady Cty. Elec. Memb. Corp.					OEMC
Gulf Coast EC, Inc.					ALEC
Habersham Elec. Memb. Corp.					OEMC
Hart Cty. Elec. Memb. Corp.					OEMC
Irwin Cty. Elec. Memb. Corp.					OEMC
Jackson Elec. Memb. Corp.					OEMC
Jefferson Elec. Memb. Corp.					OEMC
Lamar Elec. Memb. Corp.					OEMC
Little Ocmulgee Elec. Memb. Corp.					OEMC
Middle Georgia Elec. Memb. Corp.					OEMC
Mitchell Elec. Memb. Corp.					OEMC
Ocmulgee Elec. Memb. Corp.					OEMC
Oconee Elec. Memb. Copr.					OEMC, SEPA
Okefenoke Elec. Memb. Corp.					OEMC
Patuala Elec. Memb. Corp.					OEMC
Pea River EC					ALAP, ALEC
Pearl River Valley EPA					SOMI
Pioneer EC, Inc.					ALEC
Planters Elec. Memb. Corp.					OEMC
Rayla Elec. Memb. Corp.					OEMC

Southern Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Satilla Elec. Memb. Corp.					OEMC
Sawnee Elec. Memb. Corp.					OEMC
Singing River EPA					SOMI
Slash Pine Elec. Memb. Corp.					OEMC
Snapping Shoals Elec. Memb. Corp.					OEMC
So. Alabama EC, Inc.					ALEC
Southern Pine EC					ALEC
Southern Pine EPA					SOMI, MIPO
Sumter Elec. Memb. Corp.					OEMC
Tallapoosa River EC					ALEC
Three Notch Elec. Memb. Corp.					OEMC
Tombigbee River EC					ALAP, SEPA
Tri-County Elec. Memb. Corp.					OEMC
Troup County Elec. Memb. Corp.					OEMC
Upson County Elec. Memb. Corp.					OEMC
Walton Elec. Memb. Corp.					OEMC
Washington Elec. Memb. Corp.					OEMC
West Florida EC, Assn.					GUPC, SEPA
Wiregrass EC, Inc.					ALEC

Southern Subregion
Generating--Others

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Southeast Power Admin.	SEPA	1,789.0	5		

[1]Installed capacity and peakload values are from the 1978-79 "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

[2]Abbreviations are from "Plant and Ownership List - 1978," Department of Energy, DOE/E.A - 0057.

[3]Generation from the Hatch, Vogel, Wansely, and Scherer plants and 868 miles of transmission lines in Georgia are owned jointly by Dalton Water & Light Commission, Georgia Power Company, Municipal Electric Association of Georgia, and Oglethorpe Electric Membership Cooperation based on a formula related to peakloads.

[4]Southern Electric Generating Company is equally owned by Alabama Power Company and Georgia Power Company.

[5]Generation from 20 Corps of Engineers projects in Georgia, Florida, South Carolina, Virginia and Alabama is the marketing responsibility of SEPA.

NOTE: The major interconnections and power suppliers that are shown are from the "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

TVA Subregion
Generating Investor-Owned System

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Nantahala Power & Light (ALCOA)	NAPL	99.5	131.0	TEVA	TEVA

TVA Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Aberdeen Electric Dept.					TEVA
Albertville Utility Board					TEVA
Amory Electric & Water Dept.					TEVA
Athens Electric Dept.					TEVA
Athens Utility Bd.					TEVA
Benton Electric System					TEVA
Benty Co. Bd. of Pub. Utilities					TEVA
Bessemer Electric Service					TEVA
Boliver Electric Dept.					TEVA
Bowling Green Munic. Elec. Div.					TEVA
Bristol Tenn. Electric System					TEVA
Bristol Virginia Utilities Bd.					TEVA
Brownsville Utility Bd.					TEVA
Carroll County Electric Dept.					TEVA
Chattanooga Electric Power Bd.					TEVA
Chickamauga Electric System					TEVA
Cleveland Utilities					TEVA
Clinton Utilities					TEVA
Columbia Power System					TEVA
Columbus Light & Water Dept.					TEVA
Cookeville Electric Dept.					TEVA
Courtland Electric Dept.					TEVA

TVA Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Covington Electric System					TEVA
Cullman Power Board					TEVA
Dayton Electric Dept.					TEVA
Decature Electric Dept.					TEVA
Dickson Electric Dept.					TEVA
Dryersburge Electric System					TEVA
Elizabethton Electric System					TEVA
Erwin Utilities					TEVA
Etowah Utilities Dept.					TEVA
Fayetteville Electric Dept.					TEVA
Florence Electric Dept.					TEVA
Franklin Electric Plant Bd.					TEVA
Ft. Payne Improvement Auth.					TEVA
Fulton Electric System					TEVA
Gallatin Dept. of Electric					TEVA
Glasgow Electric Plant					TEVA
Greenville Light & Power					TEVA
Guntersville Electric Bd.					TEVA
Harriman Power Dept.					TEVA
Hartselle Electric Bd.					TEVA
Hickman Electric Plant Bd,					TEVA
Holly Springs Munic. Light Dept.					TEVA
Hopkinsville Electric Plant Bd.					TEVA

TVA Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Humbolt Electric Dept.					TEVA
Huntsville Utilities					TEVA
Jackson Utility Div. Elec. Dept.					TEVA
Jellico Electric System					TEVA
Johnson City Power Bd.					TEVA
Knoxville Utilities Bd.					TEVA
La Follette Electric Dept.					TEVA
Lawrenceburg Power System					TEVA
Lebanon Electric Dept.					TEVA
Lenoir City Utilities Bd.					TEVA
Lewisburg Electric System					TEVA
Loudon Utilities					TEVA
Louisville Utilities					TEVA
Macon Electric Dept.					TEVA
Maryville Utilities Bd.					TEVA
Mayfield Electric and Water System					TEVA
McMinnville Electric System					TEVA
Memphis Light, Gas, & Water Div.					TEVA
Milan Dept. of Pub. Util[4].					TEVA
Monticello Electric Plant Bd.					TEVA
Morristown Power System					TEVA
Mt. Pleasant Power System					TEVA
Murfreesboro Electric Dept.					TEVA

TVA Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Murphy Electric Power Bd.					TEVA
Muscel Shoals Electric Dept.					TEVA
Nashville Electric Service					TEVA
New Albany Water & Light Dept.					TEVA
New Bern Electric Dept.					TEVA
New Port Electric System					TEVA
Oakridge Electric Div.					TEVA
Okolona Electric Dept.					TEVA
Oxford Electric Dept.					TEVA
Paducha Power System					TEVA
Paris Bd. of Pub. Utilities					TEVA
Philadelphia Utilities					TEVA
Princeton Electric Board					TEVA
Pulaski Electric System					TEVA
Ripley Power & Light Co.					TEVA
Russelville Electric Dept.					TEVA
Russelville Electric Plant Bd.					TEVA
Scottsboro Electric Power Bd.					TEVA
Sevier Co. Electric System					TEVA
Sheffield Power and Water					TEVA
Shelbyville Power System					TEVA
Smithville Electric Dept.					TEVA
Somerville Electric Dept.					TEVA

TVA Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Sparta Electric System					TEVA
Springfield Dept. of Electricity					TEVA
Starville Electric Dept.					TEVA
Sweeteater Public Utilities					TEVA
Tarrant City Electric Dept.					TEVA
Trenton Electric Dept.					TEVA
Tullahoma Power System					TEVA
Tupelo Water & Light Dept.					TEVA
Tuscumbia Electric Dept.					TEVA
Union City Electric Dept.					TEVA
Water Valley Electric Dept.					TEVA
Weakley Co. Munic. Elec. System					TEVA
West Point Electric System					TEVA
Winchester Power System					TEVA

TVA Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Alcorn Co. EPA					TEVA
Appalachian E. C.					TEVA
Arab Electric Coop.					TEVA
Blue Ridge Mountain Electric Memb. Corp.					TEVA
Caney Fork E. C. Inc.					TEVA
Central EPA					TEVA
Cherokee Electric Coop.					TEVA
Chickasaw E. C. Inc.					TEVA
Cullman Electric Coop.					TEVA
Cumberland E. M. C.					TEVA
Duck River E. M. C.					TEVA
Forked Deer E. C. Inc.					TEVA
Fort Laudoun E. C.					TEVA
4-County EPA					TEVA
Franklin Electric Coop.					TEVA
Gibson Co. E. M. C.					TEVA
Hickman-Fulton Cnty. RECC					TEVA
Holston E. C. Inc.					TEVA
Jc Wheeler Electric Member Corp.					TEVA
Marshall-Dekalb Electric Coop.					TEVA
Meriwether Lewis E. C.					TEVA
The Middle Tennesee E. M. C.					TEVA
Monroe Co. EPA					TEVA
Mountain E. C. Inc.					TEVA

TVA Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Natchez Trace EPA					TEVA
North Alabama Electric Coop.					TEVA
Northcentral Miss. EPA					TEVA
North East Miss. EPA					TEVA
North Georgia Electric Memb. Corp.					TEVA
Pennyrile RECC					TEVA
Pickwiek E. C.					TEVA
Plateau E. C.					TEVA
Pontotoe EPA					TEVA
Powell Valley E. C.					TEVA
Powell Valley E. C. (Virginia)					TEVA
Prentiss Co. EPA					TEVA
Sand Mountain					TEVA
Sequachee Valley E. C.					TEVA
Southwest Tennesee E. M. C.					TEVA
Tallahatchie Valley EPA					TEVA
Tennessee Valley E. C.					TEVA
Tippah EPA					TEVA
Tishomingo Co. EPA					TEVA
Tombigee EPA					TEVA
Tri-County E. M. C.					TEVA
Tri-State Electric Coop.					TEVA
Tri-State Electric Corp.					TEVA

TVA Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Upper Cumberland E. M. C.					TEVA
Volunteer E. C.					TEVA
Warren RECC					TEVA
West Kentucky RECC					TEVA

TVA Subregion
Generating—Others

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Tennessee Valley Authority	TEVA	29,214.93	23,306.0	CAPO, CIEP, EAKR, ELHE, GEPC, ILPC, KEPC, KEUC, LOGE, MIPO, NAPL,	ALAP, APPC, ARPL,

[1]Installed capacity and peakload values are from the 1978-79 "Directory of Electric Utilities" Electrical World, Mc Graw Hill, Inc.

[2]Abbreviations are from "Plant and Ownership List - 1978," Department of Energy, DOE/E.A - 0057.
UNEC

[3] Includes 914.0 mw from Corp. of Engineers

NOTE: The major interconnections and power suppliers that are shown are from the "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

VACAR Subregion
Generating Investor--Owned Utilities

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Carolina Power and Light Company	CAPO	7,667.5	5,605.0	APPC, DUPC, SOCG SOCA, TEVA, YADI VIEP	APPC, DUPC, SOCG, VIEP, TEVA, SEPA, YADI, SOCA
Duke Power Company	DUPC	12,322.0	9,646.0	APPC, SOCG, CAPO, GEPC, SEPA, YADI	APPC, CAPO, GEPC, YADI, SOCG, SOCA, SEPA
Lockhart Power Company	LOHP	12.3	63.0		DUPC
South Carolina Electric and Gas Co.	SOCG	3,149.4	2,459.0	CAPO, DUPC, SEPA, GEPC, SOCA	CAPO, DUPC, SEPA, GEPC, SOCA
South Carolina Pub. Service Authority	SOCA	1,533.2	1,161.0	SOCG, SEPA, CAPO	SOCG, SEPA, CAPO
Virginia Electric and Power Company	VIEP	9,192.1	7,902.0	ALPS, APPC, CAPO, POEP	ALPS, APPC, CAPO, POEP, POEC, SEPA

VACAR Subregion
Nongenerating Investor--Owned Utilities

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Health Spring Light and Power					DUPC

VACAR Subregion
Generating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Abbeville Water & Electric Plant	ABEP	3.9	8.2		DUPC, SEPA
Blackstone Light & Power	BLSL	1.27	5.1		VIEP
Culpepper Municipal Light & Power Dept.	CULP	6.6	7.0		VIEP

VACAR Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Albemarle Water & Light Dept.					DUPC
Bamberg Board of Public Works					SOCA, SEPA
Belhaven Electric Dept.					VIEP
Benson Electric Dept.					CAPO
Bennettsville Municipal Utilities					CAPO
Bostic Electric Dept.					DUPC
Bristol Virginia Utilities Board					TEVA
Camden Municipal Utilities					CAPO
Cherryville Light Dept.					DUPC
Clayton Electric Dept.					CAPO
Clinton Combined Utility System					DUPC
Concord Board of Light & Water					DUPC
Cornelius Municipal Elec. Light Sys.					DUPC
Dallas Electric Dept.					DUPC
Drexel Electric System					DUPC, SEPA
Due West Comm. of Public Works					DUPC
Easley Combined Utility System					VIEP
Edenton Electric & Water Dept.					VIEP
Elizabeth City Dept. of Public Util.					VIEP
Elkton Electric Dept.					
Enfield Electric Utilities					

VACAR Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Farmville Water & Light Dept.					CAPO
Fayetteville Public Works Comm.					CAPO
Franklin Municipal Light Dept.					VIEP
Forest City Electric Dept.					DUPC
Fountain Electric Dept.					
Fremont Light & Water Dept.					
Front Royal Municipal Elec. Light Dept.					POEC
Gaffney Board of Public Works					DUPC
Gastonia Water & Light Dept.					DUPC
Georgetown Light & Water Dept.					SOCA
Granite Falls Electric Light Plant					DUPC
Greenwood Comm. of Public Works					DUPC, SEPA
Greenville Utilities Comm.					VIEP
Ayden Water & Light Dept.					GVUC
Winterville Electric Dept.					GVUC
Greer Comm. of Public Works					DUPU
Harrisonburg Electric Comm.					VIEP
Hertford Lighting System					VIEP
High Point Electric Utilities Dept.					DUPU
Highlands Electric Dept.					
Hobgood Municipal Electric Dept.					VIEP
Hookerton Electric Dept.					
Huntersville Electric Dept.					

VACAR Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Kings Mountain Municipal Electric Dept.					DUPC
Kinston Public Utilities					CAPO
La Grange Municipal Electric Dept.					
Landis Light & Power Dept.					DUPC
Laurens Commissioners of Public Works					DUPC, SEPA
Laurinburg Electric Dept.					CAPO
Lexington Dept. of Utilities					DUPC
Lincolnton Light & Power Dept.					DUPC
Louisburg Light & Water Plant					SEPA
Lucama Electric Dept.					
Lumberton Utilities Dept.					CAPO
Maiden Electric Utility					DUPC
Manassas Municipal Power Dept.					VIEP
Martinsville Municipal Electric Dept.					APPC
McCormick Comm. of Public Works					SOCG
Monroe Electric Dept.					DUPC
Morganton Electric Utility					DUPC
Murphy Electric Power Board					
New Bern Municipal Electric System					CAPO
Newberry Dept. of Public Utilities					DUPC
Newton Electric Dept.					DUPC
Orangeburg Dept. of Public Utilities					SOCG

VACAR Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Pikeville Electric Dept.					CAPO
Pineville Electric Co.					DUPC
Prosperity Comm. of Public Works					DUPC
Red Springs Municipal Water & Light Dept.					CAPO
Richlands Municipal Electric Dept.					APPC
Richmond Dept. of Public Utilities					VIEP
Rock Hill Electric Dept.					DUPC, SEPA
Robersonville Water & Light Comm.					VIEP
Rocky Mount Public Utilities					CAPO
Sharpsburg Electric Dept.					CAPO
Salem Municipal Electric Light Dept.					APPC
Scotland Neck Light & Water Dept.					VIEP
Selma Municipal Light & Power System					CAPO
Seneca Light & Water Dept.					DUPC
Shelby Utilities Dept.					DUPC
Smithfield Utilities Dept.					CAPO
Southport Municipal Electric Dept.					CAPO
Statesville Light Dept.					DUPC
Tarboro Municipal Light & Power Sys.					VIEP
Union Utility Dept.					

VACAR Subregion
Nongenerating Municipal Systems

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Wake Forest Electric Dept.					CAPO
Walstonburg Electric Dept.					
Washington Electric Utility					VIEP
Waynesville Municipal Electric Dept.					CAPO
Westminster Combined Utility System					
Wilson Utilities Dept.					CAPO
Stantonburg Municipal Light Dept.					WLUD
Black Creek Electric Dept.					WLUD
Windsor Electric Light & Power Co.					VIEP
Winnsboro Public Utilities					SOCG

VACAR Subregion
Generating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Central Electric Power Coop. Inc.	CEPC	192.0	691.8		SOCA, SEPA

VACAR Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Aiken Electric Cooperative, Inc.					CEPC
Albemarle Electric Membership Corp.					VIEP, SEPA
BARC Electric Cooperative					VIEP, SEPA, POEC
Berkeley Electric Cooperative, Inc.					SOCG, CEPC, SEPA
Black River Electric Cooperative, Inc.					CEPC
Blue Ridge Electric Cooperative, Inc.					DUPC, SEPA
Blue Ridge Electric Membership Corp.					DUPC, SEPA
Broad River Electric Cooperative, Inc.					DUPC, SOCG, SEPA
Brunswick Electric Membership Corp.					CAPO
Cape Hatteras Electric Membership Corp.					VIEP
Carteret-Craven Electric Membership Corp.					CAPO
Central Electric Membership Corp.					CAPO, SEPA
Central Virginia Electric Cooperative					VIEP, SEPA
Coastal Electric Cooperative, Inc.					CEPC
Community Electric Cooperative					SEPA, VIEP
Craig-Botetourt Electric Cooperative					VIEP, SEPA
Crescent Electric Membership Corp.					DUPC, SEPA
Davidson Electric Membership Corp.					DUPC
Edgecomb-Martin County Electric Corp.					VIEP, SEPA
Edisto Electric Cooperative, Inc.					CEPC
Fairfield Electric Cooperative, Inc.					CEPC
Four County Electric Membership Corp.					CAPO
French Broad Electric Membership Corp.					CAPO

VACAR Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Halifax Electric Membership Corp.					VIEP, CAPO, SEPA
Harkers Island Electric Membership Corp.					CAPO
Haywood Electric Membership Corp.					CAPO, DUPC, NAPL
Horry Electric Cooperative					CEPC
Jones-Onslow Electric Membership Corp.					CAPO
Laurens Electric Coop., Inc.					DUPC
Little River Electric Cooperative, Inc.					DUPC, SOCG
Lumbee River Electric Membership Corp.					CAPO, SEPA
Lynches River Electric Coop., Inc.					CEPC
Marlboro Electric Cooperative, Inc.					CEPC
Mechlenburg Electric Cooperative					VIEP, SEPA
Mid-Carolina Electric Coop., Inc.					CEPC
Newberry Electric Coop., Inc.					CEPC
Northern Neck Electric Coop., Inc.					VIEP, SEPA
Northern Piedmont Electric Cooperative					VIEP, SEPA
Old Dominion Electric Cooperative					VIEP
Palmetto Electric Cooperative, Inc.					CEPC, SOCG
Pee Dee Electric Cooperative, Inc.					CEPC
Pee Dee Electric Membership Corp.					CAPO, DUPC, SEPA
Piedmont Electric Membership Corp.					CAPO, DUPC, SEPA
Pitt & Greene Electric Membership Corp.					CAPO, SEPA
Powell Valley Electric Cooperative					TEVA

VACAR Subregion
Nongenerating Rural Electric Cooperatives

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
Prince George Electric Cooperative					VIEP, SEPA
Prince William Electric Cooperative					VIEP, SEPA
Randolph Electric Membership Corp.					CAPO, SEPA
Roanoke Electric Membership Corp.					VIEP, SEPA
Rutherford Electric Membership Corp.					DUPC, SEPA
Santee Electric Cooperative, Inc.					CEPC
Shenandoah Valley Electric CO-OP					VIEP, SEPA, POEC
South River Electric Membership Corp.					CAPO, SEPA
Southside Electric Cooperative, Inc.					VIEP, SEPA
Surry-Yadkin Electric Membership Corp.					DUPC
Tideland Electric Membership Corp.					VIEP, CAPO
Tri-County Electric Membership Corp.					CAPO, SEPA
Tri-County Electric Cooperative, Inc.					CEPC
Union Electric Membership Corp.					DUPC
Virginia Electric Cooperative					VIEP, SEPA
Wake Electric Membership Corp.					CAPO, DUPC, SEPA
York Electric Cooperative, Inc.					DUPC, SEPA
Univ. of North Carolina Service Plants	UNSP	12.5	76.0		DUPC

See listing in Southern Subregion for SEPA Generating Figures.

VACAR Subregion
Nongenerating--Others

Name	Code	Installed[1] Capacity 1978 MW	Peakload[1] 1978 MW	Major[2] Interconnections For Bulk Power Transactions	Power[2] Supplier
New River Light and Power Co.					SEPA, DUPC[3]

[1]Installed capacity and peakload values are from the 1978-79 "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

[2]Abbreviations are from "Plant and Ownership List - 1978," Department of Energy, DOE/E.A - 0057.

[3]Purchased through Blue Ridge Elec. Member Corp.

NOTE: The major interconnections and power suppliers that are shown are from the "Directory of Electric Utilities," Electrical World, McGraw Hill, Inc.

Code Index[1]

Code	Utility Company
ABEP	Abbeville Water & Electric Plant
ALAP	Alabama Power Co.
ALEC	Alabama Electric Coop., Inc.
ALPS	Allegheny Power Sys.
APPC	Appalachian Power Co.
ARPL	Arkansas Power & Light Co.
BIRI	Big Rivers Rural Elec. Coop.
BLSL	Blackstone Light & Power
CAPO	Carolina Power and Light Company
CCPC	Crisp County Power Comm.
CEIP	Central Illinois Pub. Ser. Co.
CEPC	Central Electric Power Coop. Inc.
CULP	Culpepper Municipal Light & Power Dept.
DUPC	Duke Power Company
EAKE	East Kentucky RECC
ELNE	Electric Energy, Inc.
FLKE	Florida Keys Electric Coop. Assn. Inc.
FLPL	Florida Power & Light Company
FPUC	Florida Public Util. (West Area)
FLPC	Florida Power Corporation
FTPA	Fort Pierce Utility Authority
GAMW	Gainesville/Alachua County Regional Utilities Board
GEPC	Georgia Power Co.
GUPC	Gulf Power Co.

Code Index[1]

Code	Utility Company
HOME	Homestead Munic. Elec. Dept.
ILPC	Illinois Power Co.
JACO	Jacksonville Electric Authority
KEUC	Kentucky Utility Co.
KEWU	Key West Utility Board
KISS	City of Kissimmee
LALW	Lakeland Dept. of Elec. & Water Utilities
LAWU	Lake Worth Utility Authority
LOGE	Louisville Gas & Electric Co.
LOHP	Lockhart Power Company
LOPL	Louisiana Power & Light Co.
MEGA	Municipal Electric Auth. of GA
MIPR	Mississippi Power Co.
NAPL	Nantahala Power & Light (ALCOA)
NESB	New Smyrna Beach Utility Commission
OEMC	Oglethorpe Elec. Memb. Corp.
ORLA	Orlando Utility Commission
POEC	Potomac Edison Company
POEP	Potomac Electric Power Co.
RCUC	Reedy Creek Utility Company, Inc.
SAEP	Savannah Electric & Power Co.
SCLW	St. Cloud Electric & Water Co.
SEBU	Sebring Utilities Commission
SEPA	Southeast Power Admin.
SIME	Seminole Electric Cooperative

Code Index[1]

Code	Utility Company
SOCA	South Carolina Pub. Service Auth.
SOCG	South Carolina Electric and Gas Co.
SOMI	South Mississippi EPA
SOEG	Southern Electric Generating Co.
STRW	Starke Light & Water Plant
TAEC	Tampa Electric Company
TALL	Tallahassee Elec. Dept.
TEVA	Tennessee Valley Authority
UNEC	Union Electric Co.
UNSP	Univ. of North Carolina Service Plants
VEBM	Vero Beach Munic. Utilities
VIEP	Virginia Electric and Power Company
WALW	Wauchula Munic. Light & Water Dept.
YADI	Yadkin, Inc.

[1]Taken from "Plant and Ownership List, Supplementary to the Maps Entitled Principal Electric Facilities, 1978" United States Department of Energy, DOE/EIA-0057.

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